Fuel Capability Demonstration Test Report 2 for the JEA Large-Scale CFB Combustion Demonstration Project

50 / 50 Blend Petroleum Coke and Pittsburgh 8 Coal Fuel

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1.0 INTRODUCTION

The agreement between the US Department of Energy (DOE) and JEA covering DOE participation in the Northside Unit 2 project required JEA to demonstrate fuel flexibility of the unit to utilize a variety of different fuels. Therefore, it was necessary for JEA to demonstrate this capability through a series of tests.

The purpose of the test program was to document the ability of the unit to utilize a variety of fuels and fuel blends in a cost effective and environmentally responsible manner. Fuel flexibility would be quantified by measuring the following parameters:

- Boiler efficiency
- CFB boiler sulfur capture
- AQCS sulfur and particulate capture
- The following flue gas emissions
    - Particulate matter (PM)
    - Oxides of nitrogen (NO_x)
    - Sulfur dioxide (SO_2)
    - Carbon monoxide (CO)
    - Carbon dioxide (CO_2)
    - Ammonia (NH_3)
    - Lead (Pb)
    - Mercury (Hg)
    - Fluorine (F)
    - Dioxin
    - Furan
- Stack opacity

This test report documents the results of JEA's Fuel Capability Demonstration Tests firing a 50/50 blend of Petroleum Coke and Pittsburgh 8 coal for the JEA Large-Scale CFB Combustion Demonstration Project. The term "blend" will be used throughout this report to describe the 50/50 blend of the two fuels. The tests were conducted in accordance with the Fuel Demonstration Test Protocol in Attachment A.

Throughout this report, unless otherwise indicated, the term "unit" refers to the combination of the circulating fluidized bed (CFB) boiler and the air quality control system (AQCS). The AQCS consists of a lime-based spray dryer absorber (SDA) and a pulse jet fabric filter (PJFF).

1.1 Test Schedule

Unit 2 of the JEA Northside plant site is a Circulating Fluidized Bed Steam Generator designed and constructed by Foster-Wheeler. The steam generator was designed to deliver main steam to the steam turbine at a flow rate of 1,993,591 lb/hr, at a throttle pressure of 2,500 psig, and at a throttle temperature of 1,000 deg F when firing Pittsburgh 8 coal.

The fuel capability demonstration test for the unit firing the blended coal was conducted over a five (5) day period beginning on January 27, 2004 and completed on January 31, 2004. During that five (5) day period, data were taken in accordance with the Test Protocol (Attachment A) while the unit was operating at 100% load, 80% load , 60% load, and 40% load.

The following log represents the sequence of testing:

- Day 1 — January 27, 2004:
  - Unit at 100% load - turbine load set and maintained at approx. 300 MW.
  - Flue gas testing commenced at 1135 hours; completed at 2026 hours.
  - Boiler performance testing commenced at 1130 hours; completed at 1530 hours.

- Day 2 — January 28, 2004:
  - Unit at 100% load - turbine load set and maintained at approx. 300 MW.
  - Flue gas testing commenced at 1000 hours; completed at 1604 hours.
  - Boiler performance testing commenced at 1000 hours.
  - The A1 fuel feeder went off-line at approximately 1230 hours. A1 fuel feeder back on line at approximately 1430 hours. The unit was allowed to stabilize. The test continued at 1600 hours. The test was completed at 1800 hours.

- Day 3 — January 29, 2004:
  - Unit at 80% load - turbine load set and maintained at approx. 240 MW.
  - Unit began 2-hour stabilization period at 240 MW at 1315 hours.
  - Boiler performance testing commenced at 1500 hours after stabilization period completed; test completed at 1900 hours.
  - Flue gas emissions data taken and recorded by CEMS system.

- Day 3 (cont'd) — January 29, 2004:
  - Unit load 60% load after completion of testing at 80% load - turbine load set and maintained at approx. 180 MW.
  - Unit began 2-hour stabilization period at 180 MW at 2000 hours.
  - Boiler performance testing commenced at 2200 hours after stabilization period completed; test completed at 0200 hours, Jan. 30, 2004.
  - Flue gas emissions data taken and recorded by CEMS system.

- Day 4 — January 30, 2004:
  - Unit load decreased to 40% load - turbine load set and maintained at approx. 120 MW.
  - Unit began 2-hour stabilization period at 120 MW at 1200 hours.
  - DCS failure tripped unit at approximately 1700 hours - 40% load test postponed until January 31, 2004.

- Day 5 — January 31, 2004:
  - Unit load set at 40% - began stabilization period at 0700 hours.
  - Boiler performance testing began at 0900 hours after stabilization period completed; test completed at 1300 hours.
  - Flue gas emissions data taken and recorded by CEMS system.
  - This concluded the testing of JEA Northside Unit 2 firing the 50/50 blended coal.

1.2 Abbreviations

Following is a definition of abbreviations used in this report. Note that at their first use, these terms are fully defined in the text of the report, followed by the abbreviation in the parenthesis. Subsequent references use the abbreviation only.

Abbreviation	Definition
A.F.	As-Fired
AQCS	Air Quality Control System
BA	Bed Ash
BOP	Balance of Plant
btu	British Thermal Unit
C	Coal
$CaCO_3$	wt. fraction $CaCO_3$ in limestone
Ca:S	Calcium to Sulfur Ration
CaO	Lime
C_b	Pounds of carbon per pound of “as-fired” fuel
CEMS	Continuous Emissions Monitoring System
CFB	Circulating Fluidized Bed
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COMS	Continuous Opacity Monitoring System
DAHS	Data Acquisition Handling System
DCS	Distributed Control System
DOE	Department of Energy
F	Fluorine or Degrees Fahrenheit
FA	Fly ash
FF	Fabric Filter
gpm	gallons per minute
gr/acf	grains per actual cubic foot

Abbreviation	Definition
gr/dscf	grains per dry standard cubic foot
$h_{\#1DRN}$	Enthalpy of drain from #1 heater
$h_{\#1INFW}$	BFW enthalpy at heater #1 inlet
$h_{\#1OUTFW}$	BFW enthalpy at heater #1 outlet
H_{EXTR1}	Enthalpy of extraction to #1 heater
Hg	Mercury
HHV	Higher Heating Value
HP	High-Pressure
H_{CRH}	Cold reheat steam enthalpy at the boiler outlet, Btu/lb
h_{FW}	Feedwater enthalpy entering the economizer, Btu/lb
H_{HRH}	Hot reheat steam enthalpy at the boiler outlet, Btu/lb
H_{MS}	Main steam enthalpy at the boiler outlet, Btu/lb
L	Lime
lb/hr	Pounds per hour
lb/MMBtu	pounds per million Btu
LS	Limestone
MBtu	Million Btu
MCR	Maximum Continuous Rating
$MgCO_3$	wt. fraction $MgCO_3$ in limestone
MU	Measurement Uncertainty
MW_X	Molecular weight of respective elements
NGS	Northside Generating Station
NH_3	Ammonia
NO_x	Oxides of Nitrogen
NS	Northside
Pb	Lead

Abbreviation	Definition
PC	Petroleum Coke
pcf	pounds per cubic foot
Pitt 8	Pittsburgh 8
PJFF	Pulse Jet Fabric Filter
PM	Particulate Matter
ppm	parts per million
ppmdv	Pounds per million, dry volume
psia	Pounds per square inch pressure absolute
psig	pounds per square inch pressure gauge
PTC	Power Test Code
RH	Reheat
S $Capture_{(AQCS)}$	Sulfur capture by the AQCS, %
SDA	Spray Dryer Absorber
S_f	Wt. fraction of sulfur in fuel, as-fired
SH	Superheat
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
$SO_{2(inlet)}$	SO_2 in the AQCS inlet (lb/MBtu)
$SO_{2(stack)}$	SO_2 in the stack (lb/MBtu)
SO_3	Sulfur Trioxide
TG	Turbine Generator
tph	tons per hour
VOC	Volatile Organic Carbon
W_l	Limestone feed rate (lb/hr)
W_{EXTR1}	Extraction flow to heater #1
W_{fe}	Fuel feed rate (lb/hr)

Abbreviation	Definition
W_{FWH}	feedwater flow at heaters
W_{MS}	Main steam flow, lb/hr
W_{RH}	Reheat steam flow, lb/hr
wt %	weight percentage

JEA Tag Number Conventions are as follows:

AA-BB-CC-xxx

AA designates GEMS Group/System, as follows:

BK = Boiler Vent and Drains
QF = Feedwater Flow
SE = Reheat Piping
SH = Reheat Superheating
SI = Secondary Superheating
SJ = Main Street Piping

BB designates major equipment codes, as follows:

12 = Control Valve
14 = Manual Valve
34 = Instrument

CC designates instrument type, as follows:

FT = Flow transmitter
FI = Flow indicator
TE = Temperature element

xxx designates numerical sequence number

2.0 SUMMARY OF TEST RESULTS

2.1 Test Requirements

The Protocol required that the following tests be performed and the results be reported at four (4) different unit loads:

- Unit Capacity, per cent (all capacities in Megawatts are gross MW).
- Boiler Efficiency, per cent (100 % load only).
- Main Steam and Reheat Steam Temperature, deg F.
- Emissions (NOx, SO2, CO, and Particulate (see Section 4.0 of this report).

No design performance data for the boiler firing the blended fuel were provided by Foster-Wheeler. For the purposes of this report, the results of the test were compared against the design performance data of the boiler produced by Foster-Wheeler, as follows:

Boiler efficiency (firing Pittsburgh 8 coal):	88.1 % HHV
Boiler efficiency (firing Pet Coke):	90.0 % HHV
Main steam flow at turbine inlet:	1,993,591 lb/hr
Main steam temperature at turbine inlet:	1,000 deg F
Main steam pressure at turbine inlet:	2,500 psig
Hot reheat steam temperature at turbine inlet:	1,000 deg F

The average steam temperatures during the Test were compared with the limits described in the following sections (The average of the readings recorded every minute shall be determined to be the Test average):

a. Main steam temperature 1000 °F +10/-0 °F at the turbine throttle valve inlet from 75 to 100% of turbine MCR and 1000 °F +/-10 °F at the turbine throttle valve inlet from 60 to 75% of turbine MCR.

b. Hot reheat steam temperature 1000 °F +10/-0 °F at the turbine intercept valve inlet from 75 to 100% of turbine MCR and 1000 °F +/-10 °F at the turbine intercept valve inlet from 60 to 75% of turbine MCR.

2.2 Valve Line-Up Requirements

With the exception of isolating the blow down systems, drain and vent systems, and the soot blower system, the boiler was operated normally in the coordinated control mode throughout the boiler efficiency test period. Prior to the start of each testing period, a walk down was conducted to confirm the ‘closed’ position of certain main steam and feedwater system valves. A listing of these valves is included in Attachment F.

2.3 Test Results

The results of the 100% tests are summarized in Table 1. The results of the part-load tests are summarized in Table 2. The performance of the boiler met and/or exceeded all of the design values provided by Foster-Wheeler. Two and a half hours into the 80% MCR test, the A1 feeder tripped. The problem was fixed, the feeder was put back on line, and the unit was ramped back up to 80% load. The testing commenced at approximately 1600 hours after the unit was allowed to stabilize - no further equipment problems were observed or recorded. No further problems with the fuel feeding system were observed or recorded during the remainder of the part-load testing periods.

TABLE 1 - TESTS RESULTS - 100% LOAD

	Design Maximum-Continuous Rating (MCR)	**January 27, 2004 Test (**corrected to MCR, see Note 4)**	**January 28, 2004 Test (**corrected to MCR, see Note 4)**
Boiler Efficiency (percent)	88.1 (Coal) 90.0 (Pet Coke)	91.6 **(Note 1)	91.7 **(Note 1)
Capacity Calculation (percent)	NA	95.3	95.4
Main Steam (Turbine Inlet)			
Flow (lb/hr)	1,993,591	1,848,031**	1,846,341**
Pressure (psig)	2,500	2,401	2,401
Temperature (°F)	1,000	1,002**	1,001**
Reheat Steam (Turbine Inlet)			
Flow (lb/hr)	1,773,263	1,776,860	1,776,167
Pressure (psig)	547.7	569.1	565.4
Temperature (°F)	1,000	1,007**	1,008**
Reheat Steam (HP Turbine Exhaust)			
Flow (lb/hr)	1,773,263	1,775,434	1,774,004
Pressure (psig)	608.6	568.4	564.9
Enthalpy (Btu/lb)	1,304.5	1,295.25	1,292.91
Feedwater to Economizer			
Temperature (°F)	487.5	484.3	483.5
50/50 Blend Fuel Analysis (As-Received)			
Carbon %	73.8	74.45	73.68
Hydrogen %	4.1	4.4	4.6
Sulfur %	5.0	5.34	5.86
Nitrogen %	1.15	1.47	1.63
Chlorine %	0.05	0.09	0.11
Oxygen %	2.20	1.25	1.26
Ash %	6.6	5.75	5.91
Moisture %	7.1	7.34	7.05
HHV (Btu/lb)	13,345	13,429	13,251
Fuel Flow Rate (lb/hr)	NA	194,172	195,177
Limestone Composition (% By Weight)			
CaCO3	92.0	91.4	86.4
MgCO3	3.0	2.95	2.82

	Design Maximum-Continuous Rating (MCR)	January 27, 2004 Test (**corrected to MCR, see Note 4)	January 28, 2004 Test (**corrected to MCR, see Note 4)
Inerts	4.0	5.15	10.43
Total Moisture	1.0	0.51	0.36
AQCS Lime Slurry Composition (% By Weight)			
CaO	85.0	46.77	47.03
MgO and inerts	15.0	53.23	52.97
AQCS Lime Slurry Density – % Solids	35	5.23	
Boiler Limestone Feedrate, lb/hr	66,056 (maximum value)	66,434	73,001
Flue Gas Emissions			
Nitrogen Oxides, NOx, lb/MMBtu (HHV)	0.09	0.07	0.07
Uncontrolled SO2, lb/MMBtu (HHV) - based on 50/50 blend	7.49	7.95	8.845
Boiler Outlet SO2, lb/MMBtu (HHV) [See Note 3]	0.78	0.2026	0.2771
Stack SO2 lb/MMBtu, (HHV)	0.15	0.093	0.11
Solid Particulate matter, baghouse outlet, lb/MMBtu (HHV)	0.011	0.0041	
Carbon Monoxide, CO, lb/MMBtu (HHV)	0.22	0.015	0.016
Opacity, percent	10	1.01	1.80
Ammonia (NH3) Slip, ppmvd	2.0	0.325	
Ammonia feed rate, gal/hr	NA	3.73	6.26
Lead, lb/MMBtu	2.60×10^{-5} (max)	8.22×10^{-7}	
Mercury (fuel and limestone), µg/g	NA	3.02×10^{-7}	
Mercury, lb/TBtu (at stack)	10.5 (max)	< 8.532 (see Note 2)	
Total Mercury Removal Efficiency, percent	No requirement	Not Utilized	
Fluoride (as HF), lb/MMBtu	1.57×10^{-4} (max)	1.69×10^{-5}	
Dioxins / Furans	No Limit	NOT TESTED	

NOTE 1: Boiler efficiency includes a value of 0.112 % for unaccounted for losses (from Foster-Wheeler data).
NOTE 2: Refer to Section 4.3.4.1.
NOTE 3: Design boiler outlet SO2 emission rate based on 85% removal of SO2 in the boiler.
NOTE 4: Corrections to design MCR conditions were made in accordance with Section 6.2.1 of Attachment A, FUEL CAPABILITY DEMONSTRATION TEST PROTOCOL.

TABLE 2 - BOILER & SDA SO2 REMOVAL EFFICIENCY

	Design Basis	January 27, 2004 Test	January 28, 2004 Test
Percent of total SO2 removed by boiler	85.0 typical, with range of 75 - 90	97.5	96.8
Percent of total SO2 removed by SDA	12.1 typical, with range 22.1 – 7.1	1.3	1.9
Percent of Total SO2 Removed	97.1	98.8	98.7
Percent of SO2 entering SDA removed in SDA	81.0 typical with range 90 – 71	54	60.3
Boiler Calcium to Sulfur Ratio	< 2.88	1.7	2.25

TABLE 3 - TEST RESULTS - PARTIAL LOADS

	Day 3	Day 4	Day 5
Unit Capacity (MW)	240	180	120
Percent MCR Load	80%	60%	40%
Capacity Calculation (percent)	76.6	58.0	38.2
Total Main Steam Flow, lb/hr	1,442,226	1,049,633	715,464
Main Steam Temperature, deg F	1,004	993	997
Main Steam Pressure, psig	2,340	1,701	1,062
Cold Reheat Steam Temperature, deg F	577.5	558.02	573.64
Hot Reheat Steam Temperature, deg F	1,006	1,011	999
NOx, lb/MMBtu	0.04	0.043	0.033
CO, lb/MMBtu	0.024	0.0276	0.08
SO2, lb/MMBtu	0.08	0.067	0.109
Opacity, percent	1.4	1.1	0.8

2.3.1 Unit Capacity - During the five (5) day testing period, the boiler was successfully operated at a turbine load of approximately 300 MW, for day 1 and day 2, and at partial turbine loads of approximately 240 MW, 180 MW, and 120 MW, for day 3, day 4, and day 5. The unit operated steadily at each of the stated loads without any deviation in unit output. Prior to each of the testing periods, the unit was brought to load and allowed to stabilize for two (2) hours prior to the start of each test.

2.3.2 Boiler Efficiency - The steam generator operated at corrected efficiencies of 91.6 % and 91.7% on Day 1 and Day 2, respectively, of the testing period. These efficiencies exceeded the design values for firing coal by approximately 3.5 %, and by approximately 1.6% for firing pet coke.

2.3.3 Steam Temperature - During both days at 100% load operation, the average corrected main steam temperature measured at the turbine inlet was 1,001 deg F, which is within the design tolerances of the unit. Additionally, the corrected hot reheat steam temperature measured at the turbine inlet was 1,018 deg F, which is also within the design tolerances of the unit. During partial load operation, the main steam temperatures and the hot reheat temperatures were within the design tolerances previously listed in Section 2.1.

2.3.4 Steam Production - The steam flows of the unit at the 100% load operation cases and partial load operation cases were each determined by adding the main steam desuperheating system flow rates to the feed water system flow rates, and subtracting the continuous blow down flow rates and the sootblowing steam flow rates. The data for each of these systems were retrieved from the plant information system database. The main steam flow rates were corrected for deviations from the design MCR feedwater temperature. Although the corrected main steam flow rates determined for the 100% load operation cases were less than the design flow rates established by Foster-Wheeler, the main steam flow rates were adequate to maintain the steam turbine at the desired plant output. The main steam flow rates at the partial load operation cases were adequate to maintain the steam turbine at the required output.

2.3.5 Calcium to Sulfur Ratio (Ca:S) - The calcium to sulfur ratio represents the ability of the CFB boiler and limestone feed system to effectively remove the sulfur dioxide produced by the combustion process of the boiler. The maximum ratio established for firing the blended coal was 2.88. The calculated calcium to sulfur ratios for Day 1 and Day 2 are approximately 1.7 and 2.25, respectively. These values represent SO2 removal efficiencies for the boiler of greater than 95 % which are acceptable values for a CFB. SO2 reductions of greater than 90% are typically achieved in a CFB with Ca:S ratios of 2 to 2.5. These values are dependent on the sulfur content in the fuel and the reactivity of the limestone.

3.0 BOILER EFFICIENCY TESTS

The unit was operated at a steady turbine load of approximately 300 MW (100% MCR) for two (2) consecutive days as prescribed in Section 2 of the Attachment A Test Protocol. During these two days, data were recorded via the PI (Plant Information) System and were also collected by independent testing contractors. These data were then used to determine the unit's boiler efficiency. No significant operational restrictions were observed during testing at the 100% MCR condition.

3.1 Calculation Method

The boiler efficiency calculation method was based on a combination of the abbreviated heat loss method as defined in the ASME Power Test Code (PTC) 4.1, 1974, reaffirmed 1991, and the methods described in ASME PTC 4. The method was modified to account for the heat of calcination and sulfation within the CFB boiler SO2 capture mechanism. The methods have also been modified to account for process differences between conventional and fluidized bed boilers to account for the addition of limestone. These modifications account for difference in the dry gas quantity and the additional heat loss/gain due to calcinations / sulfation. A complete description of the modified procedures is included in Section 4.2 of Attachment A. Some of the heat losses included losses due to the heat in dry flue gas, unburned carbon in the bed ash and the fly ash, and the heat loss due to radiation and convection from the insulated boiler surfaces. A complete list of the heat losses can be found in Section 4.2.1 of Attachment A. The completed efficiency calculations are included in Attachment F to this report.

3.2 Data and Sample Acquisition

During the tests, permanently installed plant instrumentation was used to measure most of the data which were required to perform the boiler efficiency calculations. The data were collected electronically utilizing JEA's Plant Information (PI) system. The data provided by the plant instrumentation is included in *Attachment D, PI Data Summary*. Additional data required for the boiler efficiency calculations were provided by two independent testing contractors, PGT/ESC, and Clean Air Engineering (CAE). A summary of this information is located in *Attachments G, H, I, J, and K, lab analyses provided by PGT/ESC for the fuel, limestone, bed ash, fly ash, and environmental data,* and *Attachment C, CAE Test Report,* respectively. As directed in the test protocol (Attachment A), test data for days 1 and 2 were taken and labeled by CAE and PGT. No flue gas sampling was performed on the unit during operations at reduced loads. Data were, however, recorded by the CEMS system and are reported in this document.

The majority of the data utilized in the boiler efficiency calculation and sulfur capture performance, such as combustion air and flue gas temperatures and flue gas oxygen content, were stored and retrieved by the plant information system, as noted above. Data for the as-fired fuel, limestone, and resulting bed ash, fly ash, and exiting flue gas constituents were provided via laboratory analyses. Samples were taken in the following locations by PGT and forwarded to a lab for analysis. (Refer to Figures 1 thru 6 for approximate locations).

<u>Lime (Figure 1):</u>

Lime slurry samples were taken from the sample valve located on the discharge of the lime slurry transfer pump. This valve is located in the AQCS Spray Dryer Absorber (SDA) pump room.

<u>Fly Ash (Figures 2, 3, and 4):</u>

Fly Ash samples were taken by two different methods.

1) Fly ash was taken by isokinetic sampling at the inlet to the SDA. These samples were taken to determine ash loading rates and also obtain samples for laboratory analysis of ash constituents.
2) Fly ash was also taken by grab sample method in two different locations. One grab sample was taken ever hour at a single air heater outlet hopper and another grab sample at a single bag house fabric filter hopper.

<u>Fuel (Figures 4, 5, and 6):</u>

Fuel samples were taken from the sample port at the discharge end of each gravimetric fuel feeder. The fuel samples were collected using a coal scoop inserted through the 4 inch test port at each operating fuel conveyor.

<u>Limestone (Figures 4 and 6):</u>

Limestone samples were taken from the outlet of each operating limestone rotary feeder. The samples were collected using a scoop passed into the flow stream of the 4 inch test ball valve in the neck of each feeder outlet.

<u>Bed Ash (Figure 6):</u>

Bed Ash samples were taken from each of the operating stripper cooler rotary valve outlets. The samples were taken by passing a stainless steel scoop through the 4 inch test port at each operating stripper cooler.

As instructed by the Test Protocol, all of the samples were labeled and transferred to a lab for analysis. The average values were determined and used as input data for performing the boiler efficiency calculation. The results of the lab analyses are included in Attachments G, H, I, and J.

4.0 AQCS INLET AND STACK TESTS

4.1 System Description

The Unit 2 AQCS consists of a single, lime-based spray dryer absorber (SDA) and a multi-compartment pulse jet fabric filter (PJFF). The SDA has sixteen independent dual-fluid atomizers. The fabric filter has eight isolatable compartments. The AQCS system also uses reagent preparation and byproduct handling subsystems. The SDA byproduct solids/fly ash collected by the PJFF is pneumatically transferred from the PJFF hoppers to either the Unit 2 fly ash silo or the Unit 2 AQCS recycle bin. Fly ash from the recycle bin is slurried and reused as the primary reagent by the SDA spray atomizers. The reagent preparation system converts quicklime (CaO), which is delivered dry to the station, into a hydrated lime [Ca(OH)2] slurry, which is fed to the atomizers as a supplemental reagent.

4.2 Unit Emissions Design Points

The following sections describe the desired emissions design goals of the unit. The tests were conducted in accordance with standard emissions testing practices and test methods as listed in Section 4.2.7. It should be noted that not all tests conducted fit exactly the 4 hour performance test period that was the basis of the fuel capability demonstration test. Several of the tests (especially those not based on CEMS) had durations that were different than the 4 hour performance period due to the requirements of the testing method and good engineering/testing practice. All sampling tests were done at the 100% load case only. All data at the 100%, 80%, 60% and 40% performance load tests were collected by the CEMS.

4.3 Emission Design Limits and Results

4.3.1 NOx / SO2 / Particulate Emission Design Limits / Results

The following gaseous emissions were measured for each 4-hour interval during the Test (EPA Permit averaging period).

a. **Nitrogen oxides** (NOx) values in the flue gas as measured in the stack were expected to be less than 0.09 lb/MMBtu HHV fuel heat input. The hourly average lb/MMBtu values reported by the Continuous Emissions Monitoring system (CEMS) were used as the measure of NOx in the flue gas over the course of each fuel test. The average NOx values for Day 1 and Day 2, based on HHV, were 0.07 lb/MMBtu and 0.07 lb/MMBtu, respectively. Both of these values were less than the expected maximum value.

b. **Sulfur dioxide** (SO2) The design operating condition of the unit is to remove 85 percent of the SO2 in the boiler, with the balance to make the permitted emission rate removed in the SDA. Burning performance coal with a boiler SO2 removal efficiency of 85%, the SO2 concentration at the air heater outlet was expected to be 1.12 lb/MMBtu, with an uncontrolled SO2 emission rate (at 0% SO2 removal) calculated to be 7.49 lb/MMBtu. JEA has chosen to operate at a much higher boiler SO2 removal rate than design. Part of the reason for this operating mode is that reliability of the limestone feed system during and after the startup period was inadequate, resulting in a substantial number of periods with excess SO2 emissions. Over time the operations group has learned that if limestone feed is higher than normally desired the likelihood of excess emissions during an upset is reduced. Additionally, control of the AQCS slurry density at the desired density levels has been difficult due to some instrumentation and control issues that are not completely resolved yet. Modifications to increase the reliability and consistency of limestone feed are scheduled to be complete in late 2005, which should permit a change toward lower boiler SO2 removal and increased SDA removal.

The SO2 concentration at the SDA inlet was measured by an independent test contractor, Clean Air Engineering (CAE). These results are included in Attachment C. The average SO2 values for Day 1 and Day 2, based on HHV of the fuel, out of the air heaters and into the SDA, were 0.093 lb/MMBtu and 0.11 lb/MMBtu, respectively. Both of these values were below the expected outlet emission rate. In fact, the boiler removed 98.8% and 98.7% respectively, in comparison to the design removal rate of 85%. Uncontrolled SO2 emissions rates were calculated to be 7.95 lb/MMBtu and 8.845 lb/MMBtu, respectively, for an increased SO2 input of 6.1% and 18.1% above the design performance coal SO2 input of 7.49 lb/MMBtu.

The SO2 emissions from the stack during the execution of the tests were expected to be less than 0.15 lb/MMBtu. The hourly average lb/MMBtu values (based on HHV of the fuel) reported by CEMS were used as the measure of SO2 emissions from the stack for the test. The average SO2 values for Day 1 and Day 2, (based on HHV of the fuel) were 0.102 lb/MMBtu and 0.106 lb/MMBtu, respectively. These values were 32% and 29% lower than the 0.15 lb/MMBtu permitted emission rate.

b. **Solid particulate matter** in the flue gas at the fabric filter outlet was expected to be maintained at less than 0.011 lb/MMBtu HHV fuel heat input. These values were measured at the stack by CAE. The average particulate matter value for the testing period was 0.004 lb/MMBtu which is below the expected maximum value.

4.3.2 CO Emissions Design Point

Carbon monoxide (CO) in the flue gas was expected to be less than or equal to 0.22 lb/MMBtu HHV fuel heat input at 100% MCR. This sample was measured at the stack by the plant CEMS. The average values for Day 1 and Day 2 were 0.015 lb/MMBtu and 0.016 lb/MMBtu, respectively. The average values were less than the maximum expected value.

4.3.3 SO3 Emissions Design Point

Sulfur Trioxide (SO3) in the flue gas was assumed to be zero due to the high removal efficiency of the SDA. No testing was done for SO3 as explained in the Test Protocol located in Attachment A. See Section 4.2.3 of the Fuel Capability Test Protocol for the rationale.

4.3.4 NH3/ Lead/ Mercury/ Fluorine Emissions Design Points

NH3, Lead, Mercury, and Fluorine gaseous emissions were measured during the Test (EPA Permit averaging period). Mercury sampling and analysis was performed at the inlet to the AQCS system in addition to the samples taken at the stack. Both samples were taken by CAE. Lead, ammonia and Fluorine were sampled only at the stack by CAE. The average values are indicated in Table 1.

4.3.4.1 Mercury Testing Anomaly

During the emissions tests, the reagent used in the fourth impinger of the Ontario Hydro sampling train was a 5% HNO3 (nitric acid) / 10% H2O2 (hydrogen peroxide) solution. Mercury levels in both the 5% / 10% reagent blank and the 5% / 10% portion of the field train blanks were elevated. The mercury concentration in the reagent field blanks of the other solutions (KCl, potassium chloride, and KMnO4, potassium permanganate) used in the Ontario Hydro sampling train was at the expected levels or below the detection limit. In accordance with the Ontario Hydro Method, the allowable blank adjustments have been made to the final results presented.

A review of the total mercury in the coal was completed for comparison to measured values. The coal analyses indicated a mercury content of approximately 0.003 µg/g, with a limestone mercury content of 0.03 µg/g. This is equivalent to a total mercury content of 0.0007 lb/hr. This represents more mercury than what was measured by the independent test contractor at the inlet to the SDA. However due to the bias adjustment made by the independent test contractor, the removal efficiency was lower than expected. Subsequent tests should help determine the expected mercury removal efficiency of the unit.

4.3.5 Dioxin and Furan Emissions Design Points

Dioxin and Furan gaseous emissions testing were not required for evaluation of the blended coal.

4.3.6 Opacity

The opacity was measured by the plant CEMS/COMS (Continuous Opacity Monitoring System) to determine the opacity of the unit over a six minute block average during the test period. The maximum expected opacity was 10%. The testing indicated that the maximum opacity of the unit during the two day test was 1.8%, which is much less than the maximum opacity value.

4.4 Flue Gas Emissions Test Methods

The emissions test methods used for the demonstration test were based upon utilizing 40 CFR 60 based testing methods or the plant CEMS. The emissions tests were conducted by CAE. The following test methods were utilized:

- Particulate Matter at SDA Inlet – USEPA Method 17
- Particulate Matter at Stack – USEPA Method 5
- Oxides of Nitrogen at Stack – Plant CEMS
- Sulfur Dioxide at SDA Inlet – USEPA Method 6C
- Sulfur Dioxide at Stack – Plant CEMS
- Carbon Monoxide at Stack – Plant CEMS
- Ammonia at Stack – CTM 027
- Lead at Stack – USEPA Method 29
- Mercury at SDA Inlet – Ontario Hydro Method
- Fluorine at Stack – USEPA Method 13B
- Dioxin/Furans – PCDD/F

Specific descriptions of the testing methods (non-CEMS) are included in the Clean Air Engineering Emissions Test Report located in Attachment D of this document.

4.5 Continuous Emission Monitoring System

The plant CEMS was utilized for measurement of gaseous emissions as a part of the fuel capability demonstration and as listed in Section 4.2.7. The CEMS equipment was integrated by KVB-Entertec (now GE Energy Systems). The system is a dilution extractive system consisting of Thermo Environmental NOX, SO2, and CO2 analyzers. The data listed for CEMS in Section 4.2.7 originated from the certified Data Acquisition Handling System (DAHS).

Attachments

Attachment A - Fuel Capability Demonstration Test Protocol

Attachment B - Boiler Efficiency Calculation

Attachment C - CAE Test Report

Attachment D - PI Data Summary

Attachment E - Abbreviation List

Attachment F - Isolation Valve List

Attachment G - Fuel Analyses - 50/50 Blend Pet Coke and Pittsburgh 8 Coal

Attachment H - Limestone Analyses

Attachment I - Bed Ash Analyses

Attachment J - Fly Ash (Air Heater and PJFF) Analyses

Attachment K - Ambient Data, Jan. 27, 2004 and Jan. 28, 2004

Attachment L - Ambient Temperatures, Jan. 29, 2004, Jan. 30, 2004, and Jan. 31, 2004

ATTACHMENT A

Fuel Capability Demonstration Test Protocol

This Document is located via the following link:

http://www.netl.doe.gov/cctc/resources/pdfs/jacks/FCTP.pdf

ATTACHMENT B

Boiler Efficiency Calculation

Jacksonville Electric Authority

Unit Tested:	**Northside Unit 2 - Test #2 (50/50 Blend)**	**Boiler Efficiency: 91.64**
Test Date:	**January 27, 2004**	
Test Start Time:	**11:30 AM**	
Test End Time:	**3:30 PM**	
Test Duration, hours:	**4**	

DATA INPUT SECTION - INPUT ALL DATA REQUESTED IN SECTION 1 EXCEPT AS NOTED

1. DATA REQUIRED FOR BOILER EFFICIENCY DETERMINATION

		AS - TESTED Average Value	Units	Symbol
1.1 Fuel				
1.1.1	Feed Rate, lb/h	194,172	lb/h	Wfe - Summation feeder feed rates - FN-34-FT-508, 528, 548, 568, 588, 608, 628, 668
	Composition ("as fired")			
1.1.2	Carbon, fraction	0.7445	lb/lb AF fuel	Cf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.3	Hydrogen, fraction	0.0440	lb/lb AF fuel	Hf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.4	Oxygen, fraction	0.0125	lb/lb AF fuel	Of - Laboratory analysis of coal samples obtained by grab sampling.
1.1.5	Nitrogen, fraction	0.0147	lb/lb AF fuel	Nf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.6	Sulfur, fraction	0.0534	lb/lb AF fuel	Sf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.7	Ash, fraction	0.0575	lb/lb AF fuel	Af - Laboratory analysis of coal samples obtained by grab sampling.
1.1.8	Moisture, fraction	0.0734	lb/lb AF fuel	H2Of - Laboratory analysis of coal samples obtained by grab sampling.
1.1.9	Calcium, fraction	0.0000	lb/lb AF fuel	Caf - Laboratory analysis of coal samples obtained by grab sampling - assume a value of zero if not reported.
1.1.10	HHV	13,429	Btu/lb	HHV - Laboratory analysis of coal samples obtained by grab sampling.
1.2 Limestone				
1.2.1	Feed Rate, lb/h	66,434	lb/h	Wle - Summation feeder feed rates - 2RN-53-010-Rate, 011, 012
	Composition ("as fired")			
1.2.2	CaCO3, fraction	0.9140	lb/lb limestone	CaCO3l - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.3	MgCO3, fraction	0.0295	lb/lb limestone	MgCO3l - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.4	Inerts, fraction	0.0515	lb/lb limestone	Il - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.5	Moisture, fraction	0.0051	lb/lb limestone	H2Ol - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.6	Carbonate Conversion, fraction	0.8462		XCO2 - Laboratory analysis of limestone samples obtained by grab sampling - assume value of 1 if not reportec
1.3 Bottom Ash				
1.3.1	Temperature, °F at envelope boundary	0	°F	tba - Plant instrument.
	Composition			
1.3.2	Organic Carbon, wt fraction	0.0003	lb/lb BA	Cbao - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.3	Inorganic Carbon, wt fraction	0.0000	lb/lb BA	Cbaio - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.4	Total Carbon, wt fraction - CALCULATED VALUE DO NOT ENTER	0.0003	lb/lb BA	Cba = Cbao + Cbaio
1.3.5	Calcium, wt fraction	0.2113	lb/lb BA	Caba - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.6	Carbonate as CO2, wt fraction	0.0000	lb/lb BA	CO2ba - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.7	Bottom Ash Flow By Iterative Calculation - ENTER ASSUMED VALUE TO BEGIN CALCULATION	42,543	lb/h	Wbae
1.4 Fly Ash				
	Composition			
1.4.1	Organic Carbon, wt fraction	0.0169	lb/lb FA	Cfao - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.2	Inorganic Carbon, wt fraction	0.0000	lb/lb FA	Cfaio - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.3	Carbon, wt fraction - CALCULATED VALUE DO NOT ENTER	0.0169	lb/lb FA	Cfa = Cfao + Cfaio
1.4.4	Calcium, wt fraction	0.2096	lb/lb FA	Cafa - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.5	Carbonate as CO2, wt fraction	0.0000	lb/lb FA	CO2fa - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.6	Fly Ash Flow	30,492	LB/HR	Wfam - Weight of fly ash from isokenetic sample collection.
1.5 Combustion Air				
	Primary Air			
	Hot			
1.5.1	Flow Rate, lb/h	1,761,691	lb/h	Wpae - Plant instrument.
1.5.2	Air Heater Inlet Temperature, °F	108	°F	tpa
	Cold			
1.5.3	Flow Rate, lb/h	53	LB/HR	
1.5.4	Fan Outlet Temperature, °F	108	°F	
	Secondary Air			
1.5.5	Flow Rate, lb/h	755,011	lb/h	Wsae - Plant instrument.
1.5.6	Air Heater Inlet Temperature, °F	110	°F	tsa
	Intrex Blower			
1.5.7	Flow Rate, lb/h	35,790	lb/h	Wib - Plant instrument
1.5.8	Blower Outlet Temperature, oF	166	°F	tib
	Seal Pot Blowers			
1.5.9	Flow Rate, lb/h	44706	lb/h	Wspb - Plant instrument
1.5.10	Blower Outlet Temperature, oF	178	°F	tspb

Jacksonville Electric Authority

Unit Tested:	**Northside Unit 2 - Test #2 (50/50 Blend)**	**Boiler Efficiency:**	**91.64**
Test Date:	**January 27, 2004**		
Test Start Time:	**11:30 AM**		
Test End Time:	**3:30 PM**		
Test Duration, hours:	**4**		

1.6 Ambient Conditions				
1.6.1	Ambient dry bulb temperature, °F	64.24	°F	ta
1.6.2	Ambient wet bulb temperature, °F	57.96	°F	tawb
1.6.3	Barometric pressure, inches Hg	29.99	inches Hg	Patm
1.6.4	Moisture in air, lbH2O/lb dry air	0.0087	lbH2O/lb dry air	Calculated: H2OA - From psychometric chart at temperatures ta and tawb adjusted to test Patm.
1.7 Flue Gas				
	At Air Heater Outlet			
1.7.1	Temperature (measured), °F	304.70	°F	Tg15 - Weighted average from AH outlet plant instruments (based on PA and SA flow rates)
1.7.2	Temperature (unmeasured), °F			Calculated
	Composition (wet)			
1.7.3	O2	0.0450	percent volume	O2 - Weighted average from test instrument
1.7.4	CO2	Not Measured	percent volume	CO2
1.7.5	CO	Not Measured	percent volume	CO
1.7.6	SO2	Not Measured	percent volume	SO2
	At Air Heater Inlet			
1.7.7	Temperature, °F	574.12	°F	tG14 - Plant Instrument
	Composition (wet)			
1.7.8	O2	0.0360	percent volume	
1.7.9	CO2	Not Measured	percent volume	
1.7.10	CO	Not Measured	percent volume	
1.7.11	SO2	0.0027	percent volume	measurement is in ppm
	CEM Sample Extraction At Outlet Of Economizer			
	Composition			
1.7.12	O2, percent - WET basis	3.600	percent volume	O2stk
1.7.13	SO2, ppm - dry basis	114.9	ppm	SO2stk
1.7.14	NOx, ppm - dry basis	Not Measured	ppm	Noxstk
1.7.15	CO, ppm - dry basis	Not Measured	ppm	Costk
1.7.16	Particulate, mg/Nm³	Not Measured	mg/Nm³ - 25° C	PARTstk
1.8 Feedwater				
1.8.1	Pressure, PSIG	1533.2	PSIG	pfw - Plant instrument.
1.8.2	Temperature, °F	484.3	°F	tfw - Plant instrument.
1.8.3	Flow Rate, lb/h	1,828,819	lb/h	FW - Plant instrument.
1.9 Continuous Blow Down				
1.9.1	Pressure, PSIG (drum pressure)	2,561.5	PSIG	pbd - Plant instrument
1.9.2	Temperature, °F (sat. temp. @ drum pressure)	673.7	°F	tba - Saturated water temperature from steam table at drum pressure.
1.9.3	Flow Rate, lb/h	0.00	lb/h	BD - Estimated using flow characteristic of valve and number of turns open.
1.10 Sootblowing				
1.10.1	Flow Rate, LB/HR	0.00	LB/HR	SB - Plant instrument
1.10.2	Pressure, PSIG	0.00	PSIG	psb - Plant instrument
1.10.3	Temperature, F	0.00	F	tsb - plant instrument
1.11 Main Steam Desuperheating Water				
1.11.1	Pressure, PSIG	2,700.6	PSIG	pdsw - Plant instrument.
1.11.2	Temperature, °F	303.0	°F	tdsw - Plant instrument.
1.11.3	Flow Rate, lb/h	19,086	lb/h	DSW - Plant instrument.
1.12 Main Steam				
1.12.1	Pressure, PSIG (superheater outlet)	2,400.7	PSIG	pms - Plant instrument.
1.12.2	Temperature, °F	1,003.5	°F	tms - Plant instrument.
1.12.3	Flow Rate, lb/h	1,847,905	lb/h	MS - Plant instrument - Not required to determine boiler efficiency - For information only.
1.13 Reheat Steam Desuperheating Water				
1.13.1	Pressure, PSIG	713.66	PSIG	pdswrh - Plant instrument.
1.13.2	Temperature, °F	300.87	°F	tdswrh - Plant instrument.
1.13.3	Flow Rate, lb/h	1,426	lb/h	DSWrh - Plant instrument.
1.14 Reheat Steam				
1.14.1	Inlet Pressure, PSIG	568.42	PSIG	prhin - Plant instrument.
1.14.2	Inlet Temperature, °F	604.01	°F	trhin - Plant instrument.
1.14.3	Outlet Pressure, PSIG	569.12	PSIG	prhout - Plant instrument.
1.14.4	Outlet Temperature, °F	1,007.48	°F	trhout - Plant instrument.
1.14.5	Inlet Flow, LB/HR	1,775,313	LB/HR	RHin - From turbine heat.

Jacksonville Electric Authority

Unit Tested:	Northside Unit 2 - Test #2 (50/50 Blend)	Boiler Efficiency:	91.64
Test Date:	January 27, 2004		
Test Start Time:	11:30 AM		
Test End Time:	3:30 PM		
Test Duration, hours:	4		

CALCULATION SECTION - ALL VALUES BELOW CALCULATED BY EMBEDDED FORMULAS - DO NOT ENTER DATA BELOW THIS LINE - EXCEPT ASSUMED VALUES FOR ITERATIVE CALCULATIONS

2. REFERENCE TEMPERATURES

2.1	Average Air Heater Inlet Temperature	109.29	

3. SULFUR CAPTURE

The calculation of efficiency for a circulating fluid bed steam generator that includes injection of a reactive sorbent material, such as limestone, to reduce sulfur dioxide emissions is an iterative calculation to minimize the number of parameters that have to be measured and the number of laboratory material analyses that must be performed. This both reduces the cost of the test and increases the accuracy by minimizing the impact of field and laboratory instrument inaccuracies.

To begin the process, assume a fuel flow rate. The fuel flow rate is required to complete the material balances necessary to determine the amount of limestone used and the effect of the limestone reaction on the boiler efficiency. The resulting boiler efficiency is used to calculate a value for the fuel flow rate. If the calculated flow rate is more than 1 percent different than the assumed flow rate, a new value for fuel flow rate is selected and the efficiency calculation is repeated. This process is repeated until the assumed value for fuel flow and the calculated value for fuel flow differ by less than 1 percent of of the value of the calculated fuel flow rate.

3.1	ASSUMED FUEL FLOW RATE, lb/h	182,495	lb/h	
3.2	ASSUMED SULFUR EMISSIONS, fraction	0.0295	fraction	Can get reading from CEMS system
3.3	Sulfur Capture, fraction	0.9705		

4. ASH PRODUCTION AND LIMESTONE CONSUMPTION

4.1 Accumulation of Bed Inventory 0 lb/h

4.2 Corrected Ash Carbon Content

4.2.1	Bottom Ash, fraction	0.0003	lb/lb BA
4.2.2	Fly Ash, fraction	0.0169	lb/lb FA

4.3 Bottom Ash Flow Rate

4.3.1	Total bottom ash including bed change	42,543.0267140	lb/h

4.4 Limestone Flow Rate

Iterate to determine calcium to sulfur ratio and limestone flow rate. Enter an assumed value for the calcium to sulfur ratio. Compare resulting calculated calcium to sulfur ratio to assumed value. Change assumed value until the difference between the assumed value and the calculated value is less than 1 percent of the assumed value.

4.4.1	ASSUMED CALCIUM to SULFUR RATIO	1.9940	mole Ca/mole S	
4.4.2	Solids From Limestone - estimated	0.933458109	lb/lb limestone	al = (CaCO3l * (56.0794/100.08935)) + ((CaCO3l/CaS) * (80.0622/100.08935) * XSO2) +
4.4.3	Limestone Flow Rate - estimated	66434	lb/h	Wle = ((Wfea * af * ((Caf - (Cafa/(1 - Cfai)))) + Wbae' * (1 - Cba') * ((Cafa/(1 - Cfa)) - Caba))/((Cafa/(1 -
4.4.4	Calculated Calcium to Sulfur Ratio	1.993961966	mole Ca/mole S	
	LImestone Flow Rate from PI Data, lb/h	66,434		
4.4.5	Difference Estimated vs Assumed - Ca:S	-1.65859E-05	percent	
4.4.6	Calculated Fly Ash Flow Rate	30,492	lb/h	
4.4.7	Difference Calculated vs Measured	0.0000582144	percent	

4.5 Total Dry Refuse

4.5.1	Total Dry Refuse Hourly Flow Rate	73,035	lb/h
4.5.2	Total Dry Refuse Per Pound Fuel	0.4002	lb/lb AF fuel

4.6 Heating Value Of Total Dry Refuse

4.6.1	Average Carbon Content Of Ash	0.0072	fraction
4.6.2	Heating Value Of Dry Refuse	104.84	Btu/lb

5. HEAT LOSS DUE TO DRY GAS

5.1 Carbon Burned Adjusted For Limestone

5.1.1	Carbon Burned	0.7416	lb/lb AF fuel
5.1.2	Carbon Adjusted For Limestone	0.7767	lb/lb AF fuel

Jacksonville Electric Authority			
Unit Tested:	**Northside Unit 2 - Test #2 (50/50 Blend)**	**Boiler Efficiency:**	**91.64**
Test Date:	**January 27, 2004**		
Test Start Time:	**11:30 AM**		
Test End Time:	**3:30 PM**		
Test Duration, hours:	**4**		

Determine Amount Of Flue Gas

Iterate to determine carbon dioxide volumetric content of dry flue gas. Enter an assumed value for excess air.
Compare resulting calculated oxygen content to the measure oxygen content. Change assumed value of excess air until the difference between the calculated oxygen content value and the measured value oxygen content value is less than 1 percent of the assumed value.
Use the calculated carbon dioxide value in subsequent calculations.

5.2 Air Heater Outlet

5.2.1	ASSUMED EXCESS AIR at AIR HEATER **OUTLET**	27.984	percent	
5.2.2	Corrected Stoichiometric O2, lb/lb fuel	2.3786	lb/lb AF fuel	O2stoich = (31.9988/12.01115) * Cb + (15.9994/2.01594) * Hf + (31.9998/32.064) * Sf - Of + (((Sf * 31.9988/32.064) * (XSO2) * 31.9988 * 0.5/64.0128)
5.2.3	Corrected Stoichiometric N2, lb/lb fuel	7.9007	lb/lb AF fuel	
5.2.4	Flue Gas Composition, Weight Basis, lb/lb AF Fuel			
5.2.4.1	Carbon Dioxide, weight fraction	2.8459	lb/lb AF fuel	
5.2.4.2	Sulfur Dioxide, weight fraction	0.0031	lb/lb AF fuel	
5.2.4.3	Oxygen from air less oxygen to sulfur capture, weight fraction	0.6398	lb/lb AF fuel	
5.2.4.4	Nitrogen from air, weight fraction	10.1116	lb/lb AF fuel	
5.2.4.5	Nitrogen from fuel, weight fraction	0.0147	lb/lb AF fuel	
5.2.4.6	Moisture from fuel, weight fraction	0.0734	lb/lb AF fuel	
5.2.4.7	Moisture from hydrogen in fuel, weight fraction	0.3931	lb/lb AF fuel	
5.2.4.8	Moisture from limestone, weight fraction	0.0019	lb/lb AF fuel	
5.2.4.9	Moisture from combustion air, weight fraction	0.1143	lb/lb AF fuel	
5.2.5	Weight of DRY Products of Combustion - Air Heater OUTLET	13.6151	lb/lb AF fuel	
5.2.6	Molecular Weight, lb/lb mole DRY FG - Air Heater OUTLET	30.6442	lb/lb mole	MWahoutdry = Wgcalc/((CO2calc/44.0095) + (SO2calc/64.0629) + (O2calc/31.9988) + (N2acalc/28.161) + (Nf/28.0134))
5.2.7	Weight of WET Products of Combustion - Air Heater OUTLET	14.1977	lb/lb AF fuel	
5.2.8	Molecular Weight, lb/lb mole WET FG - Air Heater OUTLET	29.7873	lb/lb AF fuel	MWahoutwet = Wgcalc/((CO2calc/44.0095) + (SO2calc/64.0629) + (O2calc/31.9988) + (N2acalc/28.161) + (Nf/28.0134) + ((H2Of + H2Oh2 + H2Ol/f + H2Oair)/18.01534)) Note: Molecular weight of nitrogen in air (N2a) is 28.161 lb/lb mole per PTC 4 Sub-Section 5.11.1 to account for trace gases in air.
5.2.9	Dry Flue Gas Composition, Volume Basis, % Dry Flue Gas			
5.2.9.1	Carbon Dioxide, volume percent	14.5543	percent volume	
5.2.9.2	Sulfur Dioxide, volume percent	0.0111	percent volume	
5.2.9.3	Oxygen from air, volume percent	4.5000	percent volume	
5.2.9.4	Nitrogen from air, volume percent	80.8166	percent volume	
5.2.9.5	Nitrogen from fuel, volume percent	0.1180	percent volume	
		100.0000	percent volume	
5.2.10	Oxygen - MEASURED AT AIR HEATER OUTLET, % vol - dry FG	4.5	percent	
5.2.11	Difference Calculated versus Measured Oxygen At Air Heater Outlet	0.00085028	percent	
5.2.12	Carbon Dioxide, DRY vol. fraction	0.1455		
5.2.13	Nitrogen (by difference), DRY vol. fraction	0.8095		
5.2.14	Weight Dry FG At Air Heater OUTLET	13.5672	lb/lb AF fuel	
5.2.15	Molecular Weight Of Dry Flue Gas At Air Heater OUTLET	30.6385	lb/lb mole	
5.2.16	Wet Flue Gas Composition, Volume Basis, % Wet Flue Gas			
5.2.16.1	Carbon Dioxide, volume percent	13.5668	percent volume	
5.2.16.2	Sulfur Dioxide, volume percent	0.01032	percent volume	
5.2.16.3	Oxygen from air, volume percent	4.1946	percent volume	
5.2.16.4	Nitrogen from air, volume percent	75.3330	percent volume	
5.2.16.5	Nitrogen from fuel, volume percent	0.1100	percent volume	
5.2.16.6	Moisture from fuel, fuel hydrogen, limestone, and air	6.7853	percent volume	H2O%out = (((H2Of + H2Oh2 + H2Ol/f + H2Oair)/18.01534) * (100)/(Wgcalcahoutwet/MWahoutwet)
		100.0000		
5.2.17	Weight Wet FG At Air Heater OUTLET	14.1498	lb/lb AF fuel	
5.2.18	Molecular Weight Of Wet Flue Gas At Air Heater OUTLET	29.7794	lb/lb mole	

5.2.19	Weight Fraction of DRY Flue Gas Components		
5.2.19.1	Oxygen, fraction weight	0.0470	fraction
5.2.19.2	Nitrogen, fraction weight	0.7440	fraction
5.2.19.3	Carbon Dioxide, fraction weight	0.2090	fraction
5.2.19.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.2.19.5	Sulfur Dioxide, fraction weight	0.0000	fraction
5.2.20	Weight Fraction of WET Flue Gas Components -NOT USED IN CALCULATION		
5.2.20.1	Oxygen, fraction weight		fraction
5.2.20.2	Nitrogen, fraction weight		fraction
5.2.20.3	Carbon Dioxide, fraction weight		fraction
5.2.20.4	Carbon Monoxide, fraction weight		fraction
5.2.20.5	Sulfur Dioxide, fraction weight		fraction
5.2.20.6	Moisture, fraction weight		fraction

5.3 Air Heater Inlet

5.3.1	ASSUMED EXCESS AIR at AIR HEATER **INLET**	21.489	percent
5.3.2	Flue Gas Composition, Weight Basis, lb/lb AF Fuel		
5.3.2.1	Carbon Dioxide, weight fraction	2.8459	lb/lb AF fuel
5.3.2.2	Sulfur Dioxide, weight fraction	0.0031	lb/lb AF fuel
5.3.2.3	Oxygen from air less oxygen to sulfur capture, weight fraction	0.4853	lb/lb AF fuel
5.3.2.4	Nitrogen from air, weight fraction	9.5984	lb/lb AF fuel
5.3.2.5	Nitrogen from fuel, weight fraction	0.0147	lb/lb AF fuel
5.3.2.6	Moisture from fuel, weight fraction	0.0734	lb/lb AF fuel
5.3.2.7	Moisture from hydrogen in fuel, weight fraction	0.3931	lb/lb AF fuel
5.3.2.8	Moisture from limestone, weight fraction	0.0019	lb/lb AF fuel
5.3.2.9	Moisture from combustion air, weight fraction	0.1085	lb/lb AF fuel
5.3.3	Weight of DRY Products of Combustion - Air Heater INLET	12.9474	lb/lb AF fuel
5.3.4	Molecular Weight, lb/lb mole DRY FG - Air Heater INLET	30.7361	lb/lb mole
5.3.5	Weight of WET Products of Combustion - Air Heater INLET	13.5242	lb/lb AF fuel
5.3.6	Molecular Weight, lb/lb mole WET FG - Air Heater INLET	29.8375	lb/lb AF fuel
5.3.7	Flue Gas Composition, Volume Basis, % DRY Flue Gas	Volume Basis % Dry Flue Gas	
5.3.7.1	Carbon Dioxide, volume percent	15.3508	percent volume
5.3.7.2	Sulfur Dioxide, volume percent	0.0117	percent volume
5.3.7.3	Oxygen from air, volume percent	3.6000	percent volume
5.3.7.4	Nitrogen from air, volume percent	80.9131	percent volume
5.3.7.5	Nitrogen from fuel, volume percent	0.1245	percent volume
		100.0000	percent volume
5.3.8	Oxygen - MEASURED AT AIR HEATER INLET, % vol - dry FG	3.6	percent
5.3.9	Difference Calculated versus Measured Oxygen At Air Heater Inlet	0.000304142	percent
5.3.10	Carbon Dioxide, DRY vol. fraction	0.1535	
5.3.11	Nitrogen (by difference), DRY vol. fraction	0.8078	
5.3.12	Weight Dry FG At Air Heater INLET	12.9405	lb/lb AF fuel
5.3.13	Molecular Weight Of Dry Flue Gas At Air Heater INLET	30.8291	lb/lb mole

		Volume Basis % Wet Flue Gas	
5.3.14	Flue Gas Composition, Volume Basis, % Wet Flue Gas		
5.3.14.1	Carbon Dioxide, volume percent	14.2664	percent volume
5.3.14.2	Sulfur Dioxide, volume percent	0.01085	percent volume
5.3.14.3	Oxygen from air, volume percent	3.3457	percent volume
5.3.14.4	Nitrogen from air, volume percent	75.1972	percent volume
5.3.14.5	Nitrogen from fuel, volume percent	0.1157	percent volume
5.3.14.6	Moisture from fuel, fuel hydrogen, limestone, and air	7.0641	percent volume
		100.0000	
5.3.15	Weight Wet FG At Air Heater INLET	13.5173	lb/lb AF fuel
5.3.16	Molecular Weight Of Wet Flue Gas At Air Heater INLET	29.9210	lb/lb mole
5.3.17	Weight Fraction of DRY Flue Gas Components		
5.3.17.1	Oxygen, fraction weight	0.0374	fraction
5.3.17.2	Nitrogen, fraction weight	0.7379	fraction
5.3.17.3	Carbon Dioxide, fraction weight	0.2191	fraction
5.3.17.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.3.17.5	Sulfur Dioxide, fraction weight	0.0056	fraction
5.3.18	Weight Fraction of WET Flue Gas Components		
5.3.18.1	Oxygen, fraction weight	0.0358	fraction
5.3.18.2	Nitrogen, fraction weight	0.7064	fraction
5.3.18.3	Carbon Dioxide, fraction weight	0.2098	fraction
5.3.18.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.3.18.5	Sulfur Dioxide, fraction weight	0.0054	fraction
5.3.18.6	Moisture, fraction weight	0.0425	fraction

5.4 CEM Sampling Location

5.4.1	ASSUMED EXCESS AIR at **CEM** SAMPLING LOCATION	23.367	percent
5.4.2	Flue Gas Composition, Weight Basis, lb/lb AF Fuel		
5.4.2.1	Carbon Dioxide, weight fraction	2.8459	lb/lb AF fuel
5.4.2.2	Sulfur Dioxide, weight fraction	0.0031	lb/lb AF fuel
5.4.2.3	Oxygen from air less oxygen to sulfur capture, weight fraction	0.5299	lb/lb AF fuel
5.4.2.4	Nitrogen from air, weight fraction	9.7468	lb/lb AF fuel
5.4.2.5	Nitrogen from fuel, weight fraction	0.0147	lb/lb AF fuel
5.4.2.6	Moisture from fuel, weight fraction	0.0734	lb/lb AF fuel
5.4.2.7	Moisture from hydrogen in fuel, weight fraction	0.3931	lb/lb AF fuel
5.4.2.8	Moisture from limestone, weight fraction	0.0019	lb/lb AF fuel
5.4.2.9	Moisture from combustion air, weight fraction	0.1102	lb/lb AF fuel
5.4.3	Weight of DRY Products of Combustion - CEM Sampling Location	13.1404	lb/lb AF fuel
5.4.4	Molecular Weight, lb/lb mole DRY FG - CEM Sampling Location	30.7085	lb/lb mole
5.4.5	Weight of WET Products of Combustion - CEM Sampling Location	13.7189	lb/lb AF fuel
5.4.6	Molecular Weight, lb/lb mole WET FG - CEM Sampling Location	29.8225	lb/lb mole

		Volume Basis % Wet Flue Gas	
5.4.7	Flue Gas Composition, Volume Basis, % WET or DRY Flue Gas		
5.4.7.1 a	Carbon Dioxide, volume percent	14.0568	percent volume
5.4.7.2 a	Sulfur Dioxide, volume percent	0.0107	percent volume
5.4.7.3 a	Oxygen from air, volume percent	3.6000	percent volume
5.4.7.4 a	Nitrogen from air, volume percent	75.2379	percent volume
5.4.7.5 a	Nitrogen from fuel, volume percent	0.1140	percent volume
5.4.7.6 a	Moisture in flue gas, volume percent	6.9806	percent volume
		100.0000	percent volume

Boiler Efficiency: 91.64

		Volume Basis % Dry Flue Gas	
5.4.7.1 b	Carbon Dioxide, volume percent	15.1117	percent volume
5.4.7.2 b	Sulfur Dioxide, volume percent	0.0115	percent volume
5.4.7.3 b	Oxygen from air, volume percent	3.8702	percent volume
5.4.7.4 b	Nitrogen from air, volume percent	80.8841	percent volume
5.4.7.5 b	Nitrogen from fuel, volume percent	0.1225	percent volume
5.4.7.6 b	Moisture in flue gas, volume percent	0.0000	percent volume
		100.0000	percent volume
5.4.8	Oxygen - MEASURED AT CEM SAMPLING LOCATION, % vol - wet I	3.6	percent volume
5.4.9	Difference Calculated versus Measured Oxygen At CEM Sample Port	-2.24399E-05	percent
5.4.10	Sulfur Dioxide - MEASURE AT CEM SAMPLING LOCATION, ppm - c	114.9	ppm
5.4.11	Difference Calculated versus Measure Sulfur Dioxide At CEM	-2.65237E-09	percent

5.5 Determine Loss Due To Dry Gas

5.5.1 Enthalpy Coefficients For Gaseous Mixtures - From PTC 4 Sub-Section 5.19.11

			Oxygen
		C0	-1.1891960E+02
		C1	4.2295190E-01
		C2	-1.6897910E-04
		C3	3.7071740E-07
		C4	-2.7439490E-10
		C5	7.384742E-14
5.5.2 a	Flue Gas Constituent Enthalpy At tG15		5.070631E+01
5.5.3 a	Flue Gas Constituent Enthalpy At tA8		7.095556E+00
			Nitrogen
		C0	-1.3472300E+02
		C1	4.6872240E-01
		C2	-8.8993190E-05
		C3	1.1982390E-07
		C4	-3.7714980E-11
		C5	-3.5026400E-16
5.5.2 b	Flue Gas Constituent Enthalpy At tG15		5.6222912E+01
5.5.3 b	Flue Gas Constituent Enthalpy At tA8		7.9570436E+00
			Carbon Dioxide
		C0	-8.5316190E+01
		C1	1.9512780E-01
		C2	3.5498060E-04
		C3	-1.7900110E-07
		C4	4.0682850E-11
		C5	1.0285430E-17
5.5.2 c	Flue Gas Constituent Enthalpy At tG15		4.9179481E+01
5.5.3 c	Flue Gas Constituent Enthalpy At tA8		6.5873912E+00
			Carbon Monoxide
		C0	-1.3574040E+02
		C1	4.7377220E-01
		C2	-1.0337790E-04
		C3	1.5716920E-07
		C4	-6.4869650E-11
		C5	6.1175980E-15
5.5.2 d	Flue Gas Constituent Enthalpy At tG15		5.6822088E+01
5.5.3 d	Flue Gas Constituent Enthalpy At tA8		8.0274306E+00

	Sulfur Dioxide
C0	-6.7416550E+01
C1	1.8238440E-01
C2	1.4862490E-04
C3	1.2737190E-08
C4	-7.3715210E-11
C5	2.8576470E-14

5.5.2 e	Flue Gas Constituent Enthalpy At tG15	3.5811376E+01	
5.5.3 e	Flue Gas Constituent Enthalpy At tA8	4.8434473E+00	

General equation for constituent enthalpy:
$h = C0 + C1 * T + C2 * T^2 + C3 * T^3 + C4 * T * T^3 + C5 * T^2 * T^3$
T = degrees Kelvin = (°F + 459.7)/1.8

5.5.4	Flue Gas Enthalpy			
5.5.5	At Measured AH Outlet Temp - tG15	54.49	Btu/lb	hFGtG15 = O2wt * hO2 + N2wt * hN2 + CO2wt * hCO2 + COwt *
5.5.6	At Measured AH Air Inlet Temp - tA8	7.63	Btu/lb	hFGtA8 = O2wt * hO2 + N2wt * hN2 + CO2wt * hCO2 + COwt * h
5.5.7	Dry Flue Gas Loss, as tested	635.78	Btu/lb AF fuel	
5.6	***HHV Percent Loss, as tested***	4.73	percent	

6. HEAT LOSS DUE TO MOISTURE CONTENT IN FUEL

6.1	Water Vapor Enthalpy at tG15 & 1 psia	1197.78	Btu/lb	$hwvtG15 = 0.4329 * tG15 + 3.958E-05 * (tG15)^2 + 1062.2 - PTC$
6.2	Saturated Water Enthalpy at tA8	77.29	Btu/lb	
6.3	Fuel Moisture Heat Loss, as tested	82.20	Btu/lb AF fuel	
6.4	***HHV Percent Loss, as tested***	0.61	percent	

7. HEAT LOSS DUE TO H2O FROM COMBUSTION OF H2 IN FUEL

7.1	H2O From H2 Heat Loss, as tested	440.48	Btu/lb AF fuel
7.2	***HHV Percent Loss, as tested***	3.28	percent

8. HEAT LOSS DUE TO COMBUSTIBLES (UNBURNED CARBON) IN ASH

8.1	Unburned Carbon In Ash Heat Loss	41.96	Btu/lb AF fuel
8.2	***HHV Percent Loss, as tested***	0.31	percent

9. HEAT LOSS DUE TO SENSIBLE HEAT IN TOTAL DRY REFUSE

9.1 Determine Dry Refuse Heat Loss Per Pound Of AF Fuel

9.1.1	Bottom Ash Heat Loss, as tested	-6.37	Btu/lb AF fuel
9.1.2	Fly Ash Heat Loss, as tested	6.53	Btu/lb AF fuel
9.2	**Total Dry Refuse Heat Loss, as tested**	0.16	Btu/lb AF fuel
9.3	***HHV Percent Loss, as tested***	0.00	percent

10. HEAT LOSS DUE TO MOISTURE IN ENTERING AIR

10.1 Determine Air Flow

10.1.1	Dry Air Per Pound Of AF Fuel	13.48	lb/lb AF fuel

10.2 Heat Loss Due To Moisture In Entering Air

10.2.1	Enthalpy Of Leaving Water Vapor	151.08	Btu/lb AF fuel
10.2.2	Enthalpy Of Entering Water Vapor	53.62	Btu/lb AF fuel
10.2.3	Air Moisture Heat Loss, as tested	11.41	Btu/lb

10.3 HHV Percent Loss, as tested 0.08 percent

11. HEAT LOSS DUE TO LIMESTONE CALCINATION/SULFATION REACTIONS

11.1 Loss To Calcination

11.1.1	Limestone Calcination Heat Loss	221.58	Btu/lb AF Fuel

11.2 Loss To Moisture In Limestone

11.2.1	Limestone Moisture Heat Loss	2.08	Btu/lb AF Fuel

11.3 Loss From Sulfation

11.3.1	Sulfation Heat Loss	-349.25	Btu/lb AF Fuel

11.4 Net Loss To Calcination/Sulfation

11.4.1	Net Limestone Reaction Heat Loss	-125.59	Btu/lb AF Fuel

11.5 HHV Percent Loss -0.94 percent

12. HEAT LOSS DUE TO SURFACE RADIATION & CONVECTION

12.1 HHV Percent Loss 0.27 percent

12.1.1	Radiation & Convection Heat Loss	36.78	Btu/lb AF fuel

13. SUMMARY OF LOSSES - AS TESTED/GUARANTEE BASIS

	As Tested Btu/lb AF Fuel
13.1.1	635.78
13.1.2	82.20
13.1.3	440.48
13.1.4	41.96
13.1.5	0.16
13.1.6	11.41
13.1.7	-125.59
13.1.8	36.78
	1,123.18

Jacksonville Electric Authority

Unit Tested:	**Northside Unit 2 - Test #2 (50/50 Blend)**
Test Date:	**January 27, 2004**
Test Start Time:	**11:30 AM**
Test End Time:	**3:30 PM**
Test Duration, hours:	**4**

Boiler Efficiency: 91.64

		As Tested Percent Loss
13.1.9	Dry Flue Gas	4.73
13.1.10	Moisture In Fuel	0.61
13.1.11	H2O From H2 In Fuel	3.28
13.1.12	Unburned Combustibles In Refuse	0.31
13.1.13	Dry Refuse	0.00
13.1.14	Moisture In Combustion Air	0.08
13.1.15	Calcination/Sulfation	-0.94
13.1.16	Radiation & Convection	0.27
		8.36

13.2 Boiler Efficiency (100 - Total Losses), percent 91.64

14. HEAT INPUT TO WATER & STEAM

14.1 Enthalpies

14.1.1	Feedwater, Btu/lb	469.42	Btu/lb
14.1.2	Blow Down, Btu/lb	738.40	Btu/lb
14.1.3	Sootblowing, Btu/lb	0.00	Btu/lb
14.1.4	Desuperheating Spray Water - Main Steam, Btu/lb	277.56	Btu/lb
14.1.5	Main Steam, Btu/lb	1463.44	Btu/lb
14.1.6	Desuperheating Spray Water - Reheat Steam, Btu/lb	271.71	Btu/lb
14.1.7	Reheat Steam - Reheater Inlet, Btu/lb	1293.94	Btu/lb
14.1.8	Reheat Steam - Reheater Outlet, Btu/lb	1521.20	Btu/lb

14.2 Heat Output 2,245,760,604 Btu/h

2,247,546,274

15. HIGHER HEATING VALUE FUEL HEAT INPUT

15.1 Determine Fuel Heat Input Based on Calculated Efficiency

15.1.1	Fuel Heat Input	2,450,735,926	Btu/h
15.1.2	Fuel Burned - CALCULATED	182,496	lb/h
15.1.3	Difference Assumed versus Calculated Fuel Burned	-0.000699774	percent

Jacksonville Electric Authority

Unit Tested:	**Northside Unit 2 - Test #2 (50/50 Blend)**	**Boiler Efficiency:**	**91.74**
Test Date:	**January 28, 2004**		
Test Start Time:	**10:00 AM**		
Test End Time:	**4:00 PM**		
Test Duration, hours:	**4**		

DATA INPUT SECTION - INPUT ALL DATA REQUESTED IN SECTION 1 EXCEPT AS NOTED

1. DATA REQUIRED FOR BOILER EFFICIENCY DETERMINATION

		AS - TESTED Average Value	Units	Symbol
1.1 Fuel				
1.1.1	Feed Rate, lb/h	195,177	lb/h	Wfe - Summation feeder feed rates - FN-34-FT-508, 528, 548, 568, 588, 608, 628, 668
	Composition ("as fired")			
1.1.2	Carbon, fraction	0.7368	lb/lb AF fuel	Cf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.3	Hydrogen, fraction	0.0460	lb/lb AF fuel	Hf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.4	Oxygen, fraction	0.0126	lb/lb AF fuel	Of - Laboratory analysis of coal samples obtained by grab sampling.
1.1.5	Nitrogen, fraction	0.0163	lb/lb AF fuel	Nf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.6	Sulfur, fraction	0.0586	lb/lb AF fuel	Sf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.7	Ash, fraction	0.0591	lb/lb AF fuel	Af - Laboratory analysis of coal samples obtained by grab sampling.
1.1.8	Moisture, fraction	0.0705	lb/lb AF fuel	H2Of - Laboratory analysis of coal samples obtained by grab sampling.
1.1.9	Calcium, fraction	0.0000	lb/lb AF fuel	Caf - Laboratory analysis of coal samples obtained by grab sampling - assume a value of zero if not reported.
1.1.10	HHV	13,251	Btu/lb	HHV - Laboratory analysis of coal samples obtained by grab sampling.
1.2 Limestone				
1.2.1	Feed Rate, lb/h	73,001	lb/h	Wle - Summation feeder feed rates - 2RN-53-010-Rate, 011, 012
	Composition ("as fired")			
1.2.2	CaCO3, fraction	0.8639	lb/lb limestone	CaCO3l - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.3	MgCO3, fraction	0.0282	lb/lb limestone	MgCO3l - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.4	Inerts, fraction	0.1043	lb/lb limestone	Il - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.5	Moisture, fraction	0.0036	lb/lb limestone	H2Ol - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.6	Carbonate Conversion, fraction	0.7909		XCO2 - Laboratory analysis of limestone samples obtained by grab sampling - assume value of 1 if not reportec
1.3 Bottom Ash				
1.3.1	Temperature, °F at envelope boundary	0	°F	tba - Plant instrument.
	Composition			
1.3.2	Organic Carbon, wt fraction	0.0001	lb/lb BA	Cbao - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.3	Inorganic Carbon, wt fraction	0.0000	lb/lb BA	Cbaio - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.4	Total Carbon, wt fraction - CALCULATED VALUE DO NOT ENTER	0.0001	lb/lb BA	Cba = Cbao + Cbaio
1.3.5	Calcium, wt fraction	0.2119	lb/lb BA	Caba - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.6	Carbonate as CO2, wt fraction	0.0000	lb/lb BA	CO2ba - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.7	Bottom Ash Flow By Iterative Calculation - ENTER ASSUMED VALUE TO BEGIN CALCULATION	54,570	lb/h	Wbae
1.4 Fly Ash				
	Composition			
1.4.1	Organic Carbon, wt fraction	0.0167	lb/lb FA	Cfao - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.2	Inorganic Carbon, wt fraction	0.0000	lb/lb FA	Cfaio - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.3	Carbon, wt fraction - CALCULATED VALUE DO NOT ENTER	0.0167	lb/lb FA	Cfa = Cfao + Cfaio
1.4.4	Calcium, wt fraction	0.2107	lb/lb FA	Cafa - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.5	Carbonate as CO2, wt fraction	0.0000	lb/lb FA	CO2fa - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.6	Fly Ash Flow	27,159	LB/HR	Wfam - Weight of fly ash from isokenetic sample collection.
1.5 Combustion Air				
	Primary Air			
	Hot			
1.5.1	Flow Rate, lb/h	1,761,691	lb/h	Wpae - Plant instrument.
1.5.2	Air Heater Inlet Temperature, °F	96	°F	tpa
	Cold			
1.5.3	Flow Rate, lb/h	54	LB/HR	
1.5.4	Fan Outlet Temperature, °F	96	°F	
	Secondary Air			
1.5.5	Flow Rate, lb/h	755,011	lb/h	Wsae - Plant instrument.
1.5.6	Air Heater Inlet Temperature, °F	95	°F	tsa
	Intrex Blower			
1.5.7	Flow Rate, lb/h	35,984	lb/h	Wib - Plant instrument
1.5.8	Blower Outlet Temperature, oF	150	°F	tib
	Seal Pot Blowers			
1.5.9	Flow Rate, lb/h	45158	lb/h	Wspb - Plant instrument
1.5.10	Blower Outlet Temperature, oF	162	°F	tspb

Jacksonville Electric Authority

Unit Tested:	**Northside Unit 2 - Test #2 (50/50 Blend)**	**Boiler Efficiency:**	**91.74**
Test Date:	**January 28, 2004**		
Test Start Time:	**10:00 AM**		
Test End Time:	**4:00 PM**		
Test Duration, hours:	**4**		

1.6 Ambient Conditions				
1.6.1	Ambient dry bulb temperature, °F	39.96	°F	ta
1.6.2	Ambient wet bulb temperature, °F	43.19	°F	tawb
1.6.3	Barometric pressure, inches Hg	30.34	inches Hg	Patm
1.6.4	Moisture in air, lbH2O/lb dry air	0.0065	lbH2O/lb dry air	Calculated: H2OA - From psychometric chart at temperatures ta and tawb adjusted to test Patm.
1.7 Flue Gas				
	At Air Heater Outlet			
1.7.1	Temperature (measured), °F	293.84	°F	Tg15 - Weighted average from AH outlet plant instruments (based on PA and SA flow rates)
1.7.2	Temperature (unmeasured), °F			Calculated
	Composition (wet)			
1.7.3	O2	0.0450	percent volume	O2 - Weighted average from test instrument
1.7.4	CO2	Not Measured	percent volume	CO2
1.7.5	CO	Not Measured	percent volume	CO
1.7.6	SO2	Not Measured	percent volume	SO2
	At Air Heater Inlet			
1.7.7	Temperature, °F	570.21	°F	tG14 - Plant Instrument
	Composition (wet)			
1.7.8	O2	0.0360	percent volume	
1.7.9	CO2	Not Measured	percent volume	
1.7.10	CO	Not Measured	percent volume	
1.7.11	SO2	0.0052	percent volume	measurement is in ppm
	CEM Sample Extraction At Outlet Of Economizer			
	Composition			
1.7.12	O2, percent - WET basis	3.600	percent volume	O2stk
1.7.13	SO2, ppm - dry basis	114.9	ppm	SO2stk
1.7.14	NOx, ppm - dry basis	Not Measured	ppm	Noxstk
1.7.15	CO, ppm - dry basis	Not Measured	ppm	Costk
1.7.16	Particulate, mg/Nm³	Not Measured	mg/Nm³ - 25° C	PARTstk
1.8 Feedwater				
1.8.1	Pressure, PSIG	1501.9	PSIG	pfw - Plant instrument.
1.8.2	Temperature, °F	483.5	°F	tfw - Plant instrument.
1.8.3	Flow Rate, lb/h	1,823,519	lb/h	FW - Plant instrument.
1.9 Continuous Blow Down				
1.9.1	Pressure, PSIG (drum pressure)	2,562.0	PSIG	pbd - Plant instrument
1.9.2	Temperature, °F (sat. temp. @ drum pressure)	673.7	°F	tba - Saturated water temperature from steam table at drum pressure.
1.9.3	Flow Rate, lb/h	0.00	lb/h	BD - Estimated using flow characteristic of valve and number of turns open.
1.10 Sootblowing				
1.10.1	Flow Rate, LB/HR	0.00	LB/HR	SB - Plant instrument
1.10.2	Pressure, PSIG	0.00	PSIG	psb - Plant instrument
1.10.3	Temperature, F	0.00	F	tsb - plant instrument
1.11 Main Steam Desuperheating Water				
1.11.1	Pressure, PSIG	2,699.7	PSIG	pdsw - Plant instrument.
1.11.2	Temperature, °F	295.1	°F	tdsw - Plant instrument.
1.11.3	Flow Rate, lb/h	22,822	lb/h	DSW - Plant instrument.
1.12 Main Steam				
1.12.1	Pressure, PSIG (superheater outlet)	2,400.9	PSIG	pms - Plant instrument.
1.12.2	Temperature, °F	1,002.7	°F	tms - Plant instrument.
1.12.3	Flow Rate, lb/h	1,846,341	lb/h	MS - Plant instrument - Not required to determine boiler efficiency - For information only.
1.13 Reheat Steam Desuperheating Water				
1.13.1	Pressure, PSIG	708.45	PSIG	pdswrh - Plant instrument.
1.13.2	Temperature, °F	316.17	°F	tdswrh - Plant instrument.
1.13.3	Flow Rate, lb/h	2,164	lb/h	DSWrh - Plant instrument.
1.14 Reheat Steam				
1.14.1	Inlet Pressure, PSIG	564.91	PSIG	prhin - Plant instrument.
1.14.2	Inlet Temperature, °F	599.83	°F	trhin - Plant instrument.
1.14.3	Outlet Pressure, PSIG	565.43	PSIG	prhout - Plant instrument.
1.14.4	Outlet Temperature, °F	1,008.17	°F	trhout - Plant instrument.
1.14.5	Inlet Flow, LB/HR	1,774,004	LB/HR	RHin - From turbine heat.

Jacksonville Electric Authority

Unit Tested:	**Northside Unit 2 - Test #2 (50/50 Blend)**
Test Date:	**January 28, 2004**
Test Start Time:	**10:00 AM**
Test End Time:	**4:00 PM**
Test Duration, hours:	**4**

Boiler Efficiency: 91.74

CALCULATION SECTION - ALL VALUES BELOW CALCULATED BY EMBEDDED FORMULAS - DO NOT ENTER DATA BELOW THIS LINE - EXCEPT ASSUMED VALUES FOR ITERATIVE CALCULATIONS

2. REFERENCE TEMPERATURES

2.1 Average Air Heater Inlet Temperature 96.32

3. SULFUR CAPTURE

The calculation of efficiency for a circulating fluid bed steam generator that includes injection of a reactive sorbent material, such as limestone, to reduce sulfur dioxide emissions is an iterative calculation to minimize the number of parameters that have to be measured and the number of laboratory material analyses that must be performed. This both reduces the cost of the test and increases the accuracy by minimizing the impact of field and laboratory instrument inaccuracies.

To begin the process, assume a fuel flow rate. The fuel flow rate is required to complete the material balances necessary to determine the amount of limestone used and the effect of the limestone reaction on the boiler efficiency. The resulting boiler efficiency is used to calculate a value for the fuel flow rate. If the calculated flow rate is more than 1 percent different than the assumed flow rate, a new value for fuel flow rate is selected and the efficiency calculation is repeated. This process is repeated until the assumed value for fuel flow and the calculated value for fuel flow differ by less than 1 percent of of the value of the calculated fuel flow rate.

3.1	ASSUMED FUEL FLOW RATE, lb/h	185,198	lb/h	
3.2	ASSUMED SULFUR EMISSIONS, fraction	0.0269	fraction	Can get reading from CEMS system
3.3	Sulfur Capture, fraction	0.9731		

4. ASH PRODUCTION AND LIMESTONE CONSUMPTION

4.1 Accumulation of Bed Inventory 0 lb/h

4.2 Corrected Ash Carbon Content

4.2.1	Bottom Ash, fraction	0.0001	lb/lb BA
4.2.2	Fly Ash, fraction	0.0167	lb/lb FA

4.3 Bottom Ash Flow Rate

4.3.1	Total bottom ash including bed change	54,570.4521370	lb/h

4.4 Limestone Flow Rate

Iterate to determine calcium to sulfur ratio and limestone flow rate. Enter an assumed value for the calcium to sulfur ratio. Compare resulting calculated calcium to sulfur ratio to assumed value. Change assumed value until the difference between the assumed value and the calculated value is less than 1 percent of the assumed value.

4.4.1	ASSUMED CALCIUM to SULFUR RATIO	1.8606	mole Ca/mole S	
4.4.2	Solids From Limestone - estimated	0.96324464	lb/lb limestone	al = (CaCO3l * (56.0794/100.08935)) + ((CaCO3l/CaS) * (80.0622/100.08935) * XSO2) +
4.4.3	Limestone Flow Rate - estimated	73001	lb/h	Wle = ((Wfea * af * ((Caf - (Cafa/(1 - Cfai)))) + Wbae' * (1 - Cba') * ((Cafa/(1 - Cfa)) - Caba))/((Cafa/(1 -
4.4.4	Calculated Calcium to Sulfur Ratio	1.860570872	mole Ca/mole S	
	LImestone Flow Rate from PI Data, lb/h	**73,001**		
4.4.5	Difference Estimated vs Assumed - Ca:S	9.12915E-06	percent	
4.4.6	Calculated Fly Ash Flow Rate	27,159	lb/h	
4.4.7	Difference Calculated vs Measured	0.0000000026	percent	

4.5 Total Dry Refuse

4.5.1	Total Dry Refuse Hourly Flow Rate	81,729	lb/h
4.5.2	Total Dry Refuse Per Pound Fuel	0.4413	lb/lb AF fuel

4.6 Heating Value Of Total Dry Refuse

4.6.1	Average Carbon Content Of Ash	0.0056	fraction
4.6.2	Heating Value Of Dry Refuse	81.44	Btu/lb

5. HEAT LOSS DUE TO DRY GAS

5.1 Carbon Burned Adjusted For Limestone

5.1.1	Carbon Burned	0.7343	lb/lb AF fuel
5.1.2	Carbon Adjusted For Limestone	0.7679	lb/lb AF fuel

Jacksonville Electric Authority

Unit Tested:	**Northside Unit 2 - Test #2 (50/50 Blend)**	**Boiler Efficiency:**	**91.74**
Test Date:	**January 28, 2004**		
Test Start Time:	**10:00 AM**		
Test End Time:	**4:00 PM**		
Test Duration, hours:	**4**		

Determine Amount Of Flue Gas

Iterate to determine carbon dioxide volumetric content of dry flue gas. Enter an assumed value for excess air.
Compare resulting calculated oxygen content to the measure oxygen content. Change assumed value of excess air until the difference between the calculated oxygen content value and the measured value oxygen content value is less than 1 percent of the assumed value.
Use the calculated carbon dioxide value in subsequent calculations.

5.2 Air Heater Outlet

5.2.1	ASSUMED EXCESS AIR at AIR HEATER **OUTLET**	28.056	percent	
5.2.2	Corrected Stoichiometric O2, lb/lb fuel	2.3817	lb/lb AF fuel	O2stoich = (31.9988/12.01115) * Cb + (15.9994/2.01594) * Hf + (31.9998/32.064) * Sf - Of + (((Sf * 31.9988/32.064) * (XSO2) * 31.9988 * 0.5/64.0128)
5.2.3	Corrected Stoichiometric N2, lb/lb fuel	7.9110	lb/lb AF fuel	
5.2.4	Flue Gas Composition, Weight Basis, lb/lb AF Fuel			
5.2.4.1	Carbon Dioxide, weight fraction	2.8135	lb/lb AF fuel	
5.2.4.2	Sulfur Dioxide, weight fraction	0.0031	lb/lb AF fuel	
5.2.4.3	Oxygen from air less oxygen to sulfur capture, weight fraction	0.6397	lb/lb AF fuel	
5.2.4.4	Nitrogen from air, weight fraction	10.1305	lb/lb AF fuel	
5.2.4.5	Nitrogen from fuel, weight fraction	0.0163	lb/lb AF fuel	
5.2.4.6	Moisture from fuel, weight fraction	0.0705	lb/lb AF fuel	
5.2.4.7	Moisture from hydrogen in fuel, weight fraction	0.4114	lb/lb AF fuel	
5.2.4.8	Moisture from limestone, weight fraction	0.0014	lb/lb AF fuel	
5.2.4.9	Moisture from combustion air, weight fraction	0.0851	lb/lb AF fuel	
5.2.5	Weight of DRY Products of Combustion - Air Heater OUTLET	13.6032	lb/lb AF fuel	
5.2.6	Molecular Weight, lb/lb mole DRY FG - Air Heater OUTLET	30.6180	lb/lb mole	MWahoutdry = Wgcalc/((CO2calc/44.0095) + (SO2calc/64.0629) + (O2calc/31.9988) + (N2acalc/28.161) + (Nf/28.0134))
5.2.7	Weight of WET Products of Combustion - Air Heater OUTLET	14.1717	lb/lb AF fuel	
5.2.8	Molecular Weight, lb/lb mole WET FG - Air Heater OUTLET	29.7822	lb/lb AF fuel	MWahoutwet = Wgcalc/((CO2calc/44.0095) + (SO2calc/64.0629) + (O2calc/31.9988) + (N2acalc/28.161) + (Nf/28.0134) + ((H2Of + H2Oh2 + H2Ol/f + H2Oair)/18.01534)) Note: Molecular weight of nitrogen in air (N2a) is 28.161 lb/lb mole per PTC 4 Sub-Section 5.11.1 to account for trace gases in air.
5.2.9	Dry Flue Gas Composition, Volume Basis, % Dry Flue Gas			
5.2.9.1	Carbon Dioxide, volume percent	14.3889	percent volume	
5.2.9.2	Sulfur Dioxide, volume percent	0.0111	percent volume	
5.2.9.3	Oxygen from air, volume percent	4.5000	percent volume	
5.2.9.4	Nitrogen from air, volume percent	80.9689	percent volume	
5.2.9.5	Nitrogen from fuel, volume percent	0.1311	percent volume	
		100.0000	percent volume	
5.2.10	Oxygen - MEASURED AT AIR HEATER OUTLET, % vol - dry FG	4.5	percent	
5.2.11	Difference Calculated versus Measured Oxygen At Air Heater Outlet	0.000647346	percent	
5.2.12	Carbon Dioxide, DRY vol. fraction	0.1439		
5.2.13	Nitrogen (by difference), DRY vol. fraction	0.8111		
5.2.14	Weight Dry FG At Air Heater OUTLET	13.5512	lb/lb AF fuel	
5.2.15	Molecular Weight Of Dry Flue Gas At Air Heater OUTLET	30.6147	lb/lb mole	
5.2.16	Wet Flue Gas Composition, Volume Basis, % Wet Flue Gas			
5.2.16.1	Carbon Dioxide, volume percent	13.4347	percent volume	
5.2.16.2	Sulfur Dioxide, volume percent	0.01033	percent volume	
5.2.16.3	Oxygen from air, volume percent	4.2015	percent volume	
5.2.16.4	Nitrogen from air, volume percent	75.5993	percent volume	
5.2.16.5	Nitrogen from fuel, volume percent	0.1224	percent volume	
5.2.16.6	Moisture from fuel, fuel hydrogen, limestone, and air	6.6317	percent volume	H2O%out = (((H2Of + H2Oh2 + H2Ol/f + H2Oair)/18.01534) * (100)/(Wgcalcahoutwet/MWahoutwet)
		100.0000		
5.2.17	Weight Wet FG At Air Heater OUTLET	14.1197	lb/lb AF fuel	
5.2.18	Molecular Weight Of Wet Flue Gas At Air Heater OUTLET	29.7763	lb/lb mole	

5.2.19	Weight Fraction of DRY Flue Gas Components		
5.2.19.1	Oxygen, fraction weight	0.0470	fraction
5.2.19.2	Nitrogen, fraction weight	0.7461	fraction
5.2.19.3	Carbon Dioxide, fraction weight	0.2069	fraction
5.2.19.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.2.19.5	Sulfur Dioxide, fraction weight	0.0000	fraction
5.2.20	Weight Fraction of WET Flue Gas Components -NOT USED IN CALCULATION		
5.2.20.1	Oxygen, fraction weight		fraction
5.2.20.2	Nitrogen, fraction weight		fraction
5.2.20.3	Carbon Dioxide, fraction weight		fraction
5.2.20.4	Carbon Monoxide, fraction weight		fraction
5.2.20.5	Sulfur Dioxide, fraction weight		fraction
5.2.20.6	Moisture, fraction weight		fraction

5.3 Air Heater Inlet

5.3.1	ASSUMED EXCESS AIR at AIR HEATER **INLET**	21.569	percent
5.3.2	Flue Gas Composition, Weight Basis, lb/lb AF Fuel		
5.3.2.1	Carbon Dioxide, weight fraction	2.8135	lb/lb AF fuel
5.3.2.2	Sulfur Dioxide, weight fraction	0.0031	lb/lb AF fuel
5.3.2.3	Oxygen from air less oxygen to sulfur capture, weight fraction	0.4852	lb/lb AF fuel
5.3.2.4	Nitrogen from air, weight fraction	9.6173	lb/lb AF fuel
5.3.2.5	Nitrogen from fuel, weight fraction	0.0163	lb/lb AF fuel
5.3.2.6	Moisture from fuel, weight fraction	0.0705	lb/lb AF fuel
5.3.2.7	Moisture from hydrogen in fuel, weight fraction	0.4114	lb/lb AF fuel
5.3.2.8	Moisture from limestone, weight fraction	0.0014	lb/lb AF fuel
5.3.2.9	Moisture from combustion air, weight fraction	0.0808	lb/lb AF fuel
5.3.3	Weight of DRY Products of Combustion - Air Heater INLET	12.9355	lb/lb AF fuel
5.3.4	Molecular Weight, lb/lb mole DRY FG - Air Heater INLET	30.7084	lb/lb mole
5.3.5	Weight of WET Products of Combustion - Air Heater INLET	13.4997	lb/lb AF fuel
5.3.6	Molecular Weight, lb/lb mole WET FG - Air Heater INLET	29.8301	lb/lb AF fuel
5.3.7	Flue Gas Composition, Volume Basis, % DRY Flue Gas	Volume Basis % Dry Flue Gas	
5.3.7.1	Carbon Dioxide, volume percent	15.1763	percent volume
5.3.7.2	Sulfur Dioxide, volume percent	0.0117	percent volume
5.3.7.3	Oxygen from air, volume percent	3.6000	percent volume
5.3.7.4	Nitrogen from air, volume percent	81.0737	percent volume
5.3.7.5	Nitrogen from fuel, volume percent	0.1383	percent volume
		100.0000	percent volume
5.3.8	Oxygen - MEASURED AT AIR HEATER INLET, % vol - dry FG	3.6	percent
5.3.9	Difference Calculated versus Measured Oxygen At Air Heater Inlet	0.000655001	percent
5.3.10	Carbon Dioxide, DRY vol. fraction	0.1518	
5.3.11	Nitrogen (by difference), DRY vol. fraction	0.8071	
5.3.12	Weight Dry FG At Air Heater INLET	12.9631	lb/lb AF fuel
5.3.13	Molecular Weight Of Dry Flue Gas At Air Heater INLET	30.8923	lb/lb mole

		Volume Basis % Wet Flue Gas	
5.3.14	Flue Gas Composition, Volume Basis, % Wet Flue Gas		
5.3.14.1	Carbon Dioxide, volume percent	14.1261	percent volume
5.3.14.2	Sulfur Dioxide, volume percent	0.01086	percent volume
5.3.14.3	Oxygen from air, volume percent	3.3509	percent volume
5.3.14.4	Nitrogen from air, volume percent	75.4633	percent volume
5.3.14.5	Nitrogen from fuel, volume percent	0.1287	percent volume
5.3.14.6	Moisture from fuel, fuel hydrogen, limestone, and air	6.9201	percent volume
		100.0000	
5.3.15	Weight Wet FG At Air Heater INLET	13.5273	lb/lb AF fuel
5.3.16	Molecular Weight Of Wet Flue Gas At Air Heater INLET	29.9981	lb/lb mole
5.3.17	Weight Fraction of DRY Flue Gas Components		
5.3.17.1	Oxygen, fraction weight	0.0373	fraction
5.3.17.2	Nitrogen, fraction weight	0.7357	fraction
5.3.17.3	Carbon Dioxide, fraction weight	0.2163	fraction
5.3.17.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.3.17.5	Sulfur Dioxide, fraction weight	0.0108	fraction
5.3.18	Weight Fraction of WET Flue Gas Components		
5.3.18.1	Oxygen, fraction weight	0.0357	fraction
5.3.18.2	Nitrogen, fraction weight	0.7050	fraction
5.3.18.3	Carbon Dioxide, fraction weight	0.2072	fraction
5.3.18.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.3.18.5	Sulfur Dioxide, fraction weight	0.0103	fraction
5.3.18.6	Moisture, fraction weight	0.0416	fraction

5.4 CEM Sampling Location

5.4.1	ASSUMED EXCESS AIR at **CEM** SAMPLING LOCATION	23.402	percent
5.4.2	Flue Gas Composition, Weight Basis, lb/lb AF Fuel		
5.4.2.1	Carbon Dioxide, weight fraction	2.8135	lb/lb AF fuel
5.4.2.2	Sulfur Dioxide, weight fraction	0.0031	lb/lb AF fuel
5.4.2.3	Oxygen from air less oxygen to sulfur capture, weight fraction	0.5289	lb/lb AF fuel
5.4.2.4	Nitrogen from air, weight fraction	9.7623	lb/lb AF fuel
5.4.2.5	Nitrogen from fuel, weight fraction	0.0163	lb/lb AF fuel
5.4.2.6	Moisture from fuel, weight fraction	0.0705	lb/lb AF fuel
5.4.2.7	Moisture from hydrogen in fuel, weight fraction	0.4114	lb/lb AF fuel
5.4.2.8	Moisture from limestone, weight fraction	0.0014	lb/lb AF fuel
5.4.2.9	Moisture from combustion air, weight fraction	0.0820	lb/lb AF fuel
5.4.3	Weight of DRY Products of Combustion - CEM Sampling Location	13.1242	lb/lb AF fuel
5.4.4	Molecular Weight, lb/lb mole DRY FG - CEM Sampling Location	30.6819	lb/lb mole
5.4.5	Weight of WET Products of Combustion - CEM Sampling Location	13.6896	lb/lb AF fuel
5.4.6	Molecular Weight, lb/lb mole WET FG - CEM Sampling Location	29.8160	lb/lb mole

		Volume Basis % Wet Flue Gas	
5.4.7	Flue Gas Composition, Volume Basis, % WET or DRY Flue Gas		
5.4.7.1 a	Carbon Dioxide, volume percent	13.9236	percent volume
5.4.7.2 a	Sulfur Dioxide, volume percent	0.0107	percent volume
5.4.7.3 a	Oxygen from air, volume percent	3.6000	percent volume
5.4.7.4 a	Nitrogen from air, volume percent	75.5031	percent volume
5.4.7.5 a	Nitrogen from fuel, volume percent	0.1269	percent volume
5.4.7.6 a	Moisture in flue gas, volume percent	6.8357	percent volume
		100.0000	percent volume

Jacksonville Electric Authority

Unit Tested:	Northside Unit 2 - Test #2 (50/50 Blend)
Test Date:	January 28, 2004
Test Start Time:	10:00 AM
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Test Duration, hours:	4

Boiler Efficiency: 91.74

		Volume Basis % Dry Flue Gas	
5.4.7.1 b	Carbon Dioxide, volume percent	14.9452	percent volume
5.4.7.2 b	Sulfur Dioxide, volume percent	0.0115	percent volume
5.4.7.3 b	Oxygen from air, volume percent	3.8641	percent volume
5.4.7.4 b	Nitrogen from air, volume percent	81.0430	percent volume
5.4.7.5 b	Nitrogen from fuel, volume percent	0.1362	percent volume
5.4.7.6 b	Moisture in flue gas, volume percent	0.0000	percent volume
		100.0000	percent volume

5.4.8	Oxygen - MEASURED AT CEM SAMPLING LOCATION, % vol - wet I	3.6	percent volume
5.4.9	Difference Calculated versus Measured Oxygen At CEM Sample Port	-4.148E-06	percent
5.4.10	Sulfur Dioxide - MEASURE AT CEM SAMPLING LOCATION, ppm - c	114.9	ppm
5.4.11	Difference Calculated versus Measure Sulfur Dioxide At CEM	0.000940575	percent

5.5 Determine Loss Due To Dry Gas

5.5.1 Enthalpy Coefficients For Gaseous Mixtures - From PTC 4 Sub-Section 5.19.11

			Oxygen
		C0	-1.1891960E+02
		C1	4.2295190E-01
		C2	-1.6897910E-04
		C3	3.7071740E-07
		C4	-2.7439490E-10
		C5	7.384742E-14
5.5.2 a	Flue Gas Constituent Enthalpy At tG15		4.824907E+01
5.5.3 a	Flue Gas Constituent Enthalpy At tA8		4.242769E+00

			Nitrogen
		C0	-1.3472300E+02
		C1	4.6872240E-01
		C2	-8.8993190E-05
		C3	1.1982390E-07
		C4	-3.7714980E-11
		C5	-3.5026400E-16
5.5.2 b	Flue Gas Constituent Enthalpy At tG15		5.3532667E+01
5.5.3 b	Flue Gas Constituent Enthalpy At tA8		4.7612480E+00

			Carbon Dioxide
		C0	-8.5316190E+01
		C1	1.9512780E-01
		C2	3.5498060E-04
		C3	-1.7900110E-07
		C4	4.0682850E-11
		C5	1.0285430E-17
5.5.2 c	Flue Gas Constituent Enthalpy At tG15		4.6700315E+01
5.5.3 c	Flue Gas Constituent Enthalpy At tA8		3.9252409E+00

			Carbon Monoxide
		C0	-1.3574040E+02
		C1	4.7377220E-01
		C2	-1.0337790E-04
		C3	1.5716920E-07
		C4	-6.4869650E-11
		C5	6.1175980E-15
5.5.2 d	Flue Gas Constituent Enthalpy At tG15		5.4097371E+01
5.5.3 d	Flue Gas Constituent Enthalpy At tA8		4.8028593E+00

Jacksonville Electric Authority

Unit Tested:	**Northside Unit 2 - Test #2 (50/50 Blend)**
Test Date:	**January 28, 2004**
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Test Duration, hours:	**4**

Boiler Efficiency: 91.74

	Sulfur Dioxide
C0	-6.7416550E+01
C1	1.8238440E-01
C2	1.4862490E-04
C3	1.2737190E-08
C4	-7.3715210E-11
C5	2.8576470E-14

5.5.2 e	Flue Gas Constituent Enthalpy At tG15	3.4021227E+01		
5.5.3 e	Flue Gas Constituent Enthalpy At tA8	2.8883721E+00		

General equation for constituent enthalpy:
h = C0 + C1 * T + C2 * T² + C3 * T³ + C4 * T * T³ + C5 * T² * T³
T = degrees Kelvin = (°F + 459.7)/1.8

5.5.4	Flue Gas Enthalpy			
5.5.5	At Measured AH Outlet Temp - tG15	51.87	Btu/lb	hFGtG15 = O2wt * hO2 + N2wt * hN2 + CO2wt * hCO2 + COwt *
5.5.6	At Measured AH Air Inlet Temp - tA8	4.56	Btu/lb	hFGtA8 = O2wt * hO2 + N2wt * hN2 + CO2wt * hCO2 + COwt * h
5.5.7	Dry Flue Gas Loss, as tested	641.07	Btu/lb AF fuel	
5.6	***HHV Percent Loss, as tested***	4.84	percent	

6. HEAT LOSS DUE TO MOISTURE CONTENT IN FUEL

6.1	Water Vapor Enthalpy at tG15 & 1 psia	1192.82	Btu/lb	hwvtG15 = 0.4329 * tG15 + 3.958E-05 * (tG15)² + 1062.2 - PTC
6.2	Saturated Water Enthalpy at tA8	64.32	Btu/lb	
6.3	Fuel Moisture Heat Loss, as tested	79.59	Btu/lb AF fuel	
6.4	***HHV Percent Loss, as tested***	0.60	percent	

7. HEAT LOSS DUE TO H2O FROM COMBUSTION OF H2 IN FUEL

7.1	H2O From H2 Heat Loss, as tested	464.30	Btu/lb AF fuel
7.2	***HHV Percent Loss, as tested***	3.50	percent

8. HEAT LOSS DUE TO COMBUSTIBLES (UNBURNED CARBON) IN ASH

8.1	Unburned Carbon In Ash Heat Loss	35.94	Btu/lb AF fuel
8.2	***HHV Percent Loss, as tested***	0.27	percent

9. HEAT LOSS DUE TO SENSIBLE HEAT IN TOTAL DRY REFUSE

9.1 Determine Dry Refuse Heat Loss Per Pound Of AF Fuel

9.1.1	Bottom Ash Heat Loss, as tested	-7.10	Btu/lb AF fuel
9.1.2	Fly Ash Heat Loss, as tested	5.79	Btu/lb AF fuel
9.2	**Total Dry Refuse Heat Loss, as tested**	-1.30	Btu/lb AF fuel
9.3	***HHV Percent Loss, as tested***	-0.01	percent

10. HEAT LOSS DUE TO MOISTURE IN ENTERING AIR

10.1 Determine Air Flow

10.1.1	Dry Air Per Pound Of AF Fuel	13.50	lb/lb AF fuel

10.2 Heat Loss Due To Moisture In Entering Air

10.2.1	Enthalpy Of Leaving Water Vapor	145.61	Btu/lb AF fuel
10.2.2	Enthalpy Of Entering Water Vapor	47.22	Btu/lb AF fuel
10.2.3	Air Moisture Heat Loss, as tested	8.58	Btu/lb

10.3 HHV Percent Loss, as tested 0.06 percent

11. HEAT LOSS DUE TO LIMESTONE CALCINATION/SULFATION REACTIONS

11.1 Loss To Calcination

11.1.1	Limestone Calcination Heat Loss	212.04	Btu/lb AF Fuel

11.2 Loss To Moisture In Limestone

11.2.1	Limestone Moisture Heat Loss	1.60	Btu/lb AF Fuel

11.3 Loss From Sulfation

11.3.1	Sulfation Heat Loss	-384.13	Btu/lb AF Fuel

11.4 Net Loss To Calcination/Sulfation

11.4.1	Net Limestone Reaction Heat Loss	-170.49	Btu/lb AF Fuel

11.5 HHV Percent Loss -1.29 percent

12. HEAT LOSS DUE TO SURFACE RADIATION & CONVECTION

12.1 HHV Percent Loss 0.27 percent

12.1.1	Radiation & Convection Heat Loss	36.22	Btu/lb AF fuel

13. SUMMARY OF LOSSES - AS TESTED/GUARANTEE BASIS

	As Tested Btu/lb AF Fuel
13.1.1	641.07
13.1.2	79.59
13.1.3	464.30
13.1.4	35.94
13.1.5	-1.30
13.1.6	8.58
13.1.7	-170.49
13.1.8	36.22
	1,093.91

Jacksonville Electric Authority	
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Boiler Efficiency: 91.74

		As Tested Percent Loss
13.1.9	Dry Flue Gas	4.84
13.1.10	Moisture In Fuel	0.60
13.1.11	H2O From H2 In Fuel	3.50
13.1.12	Unburned Combustibles In Refuse	0.27
13.1.13	Dry Refuse	-0.01
13.1.14	Moisture In Combustion Air	0.06
13.1.15	Calcination/Sulfation	-1.29
13.1.16	Radiation & Convection	0.27
		8.26
13.2	***Boiler Efficiency (100 - Total Losses), percent***	***91.74***

14. HEAT INPUT TO WATER & STEAM

14.1 Enthalpies

14.1.1	Feedwater, Btu/lb	468.53	Btu/lb
14.1.2	Blow Down, Btu/lb	738.47	Btu/lb
14.1.3	Sootblowing, Btu/lb	0.00	Btu/lb
14.1.4	Desuperheating Spray Water - Main Steam, Btu/lb	269.63	Btu/lb
14.1.5	Main Steam, Btu/lb	1462.92	Btu/lb
14.1.6	Desuperheating Spray Water - Reheat Steam, Btu/lb	287.42	Btu/lb
14.1.7	Reheat Steam - Reheater Inlet, Btu/lb	1291.55	Btu/lb
14.1.8	Reheat Steam - Reheater Outlet, Btu/lb	1521.67	Btu/lb

14.2 Heat Output 2,251,429,948 Btu/h

2,253,136,163

15. HIGHER HEATING VALUE FUEL HEAT INPUT

15.1 Determine Fuel Heat Input Based on Calculated Efficiency

15.1.1	Fuel Heat Input	2,454,020,283	Btu/h
15.1.2	Fuel Burned - CALCULATED	185,199	lb/h
15.1.3	Difference Assumed versus Calculated Fuel Burned	-0.000322748	percent

ATTACHMENT C

CAE Test Report

Black & Veatch Corporation
10751 Deerwood Park Boulevard, Suite 130
Jacksonville, FL 32256

REPORT ON
LARGE SCALE CFB COMBUSTION DEMONSTRATION PROJECT
50% PITTSBURGH NO. 8 COAL
50% PETROLEUM COKE

Performed for:
BLACK & VEATCH CORPORATION
UNIT 2, SDA INLET AND STACK
JEA - NORTHSIDE GENERATING STATION

Client Reference No: 137064.96.1400
CleanAir Project No: 9475-2
Revision 0: March 9, 2004

To the best of our knowledge, the data presented in this report are accurate and complete and error free, legible and representative of the actual emissions during the test program.

Submitted by,

Robert A. Preksta
Project Manager
(412) 787-9130
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Reviewed by,

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CONTENTS

PROJECT OVERVIEW

The Northside Generating Station Repowering project provided JEA (formerly the Jacksonville Electric Authority) with the two largest circulating fluidized bed (CFB) boilers in the world. The agreement between the US Department of Energy (DOE) and JEA covering DOE participation in the Northside Unit 2 project required JEA to demonstrate the ability of the unit to utilize a variety of different fuels. Black and Veatch Corporation (B&V) contracted Clean Air Engineering, Inc. (CleanAir) to perform the air emission measurements required as part of the demonstration test program. This report covers air emission measurements obtained during the firing of a blend of 50% Pittsburgh No. 8 coal and 50% Petroleum Coke to the unit.

The test program included the measurement of the following parameters:

- particulate matter (PM), [SDA Inlet and Stack];
- sulfur dioxide (SO_2), [SDA Inlet];
- fluoride (F), [Stack];
- lead (Pb), [Stack];
- speciation of mercury (Hg^0, Hg^{2+}, Hg^{tp}), [SDA Inlet and Stack];
- ammonia (NH_3).

The field portion of the test program took place at the Unit 2 SDA Inlet and Stack locations on January 27 and 28, 2004. Coordinating the field portion of the testing were:

T. Compaan – Black and Veatch
R. Huggins – Black and Veatch
W. Goodrich - JEA
K. Davis - JEA
J. Martin - RMB
J. Stroud - Clean Air Engineering

Table 1-1 contains a summary of the specific test locations, various reference methods and sampling periods for each of the sources sampled during the program.

The results of the test program are summarized in Table 1-2. A more detailed presentation of the test data is contained in Tables 2-1 through 2-10. Process data collected during the test program is contained in Appendix H.

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**Table 1-1:
Summary of Air Emission Field Test Program**

Run Number	Location	Method	Analyte	Date	Start Time	End Time	Notes
1	Unit 2 - SDA Inlet	USEPA Method 17	Particulate	1/27/04	11:35	12:44	
2	Unit 2 - SDA Inlet	USEPA Method 17	Particulate	1/27/04	13:11	14:18	
3	Unit 2 - SDA Inlet	USEPA Method 17	Particulate	1/27/04	14:57	16:04	
1	Unit 2 - SDA Inlet	Method 6C	SO2	1/27/04	11:35	12:35	
2	Unit 2 - SDA Inlet	Method 6C	SO2	1/27/04	13:11	14:11	
3	Unit 2 - SDA Inlet	Method 6C	SO2	1/27/04	14:57	15:57	
1	Unit 2 - SDA Inlet	Ontario Hydro	Mercury	1/27/04	11:30	13:36	
2	Unit 2 - SDA Inlet	Ontario Hydro	Mercury	1/27/04	14:58	17:57	
3	Unit 2 - SDA Inlet	Ontario Hydro	Mercury	1/27/04	18:14	20:26	
1	Unit 2 Stack	USEPA Method 5/29	Particulate/Metals	1/27/04	08:00	10:07	
2	Unit 2 Stack	USEPA Method 5/29	Particulate/Metals	1/27/04	10:35	12:43	
3	Unit 2 Stack	USEPA Method 5/29	Particulate/Metals	1/27/04	13:08	15:20	
1	Unit 2 Stack	Ontario Hydro	Mercury	1/27/04	11:30	13:39	
2	Unit 2 Stack	Ontario Hydro	Mercury	1/27/04	14:58	17:54	
3	Unit 2 Stack	Ontario Hydro	Mercury	1/27/04	18:14	20:23	
4	Unit 2 - SDA Inlet	USEPA Method 17	Particulate	1/28/04	10:00	11:03	
5	Unit 2 - SDA Inlet	USEPA Method 17	Particulate	1/28/04	11:10	12:16	
6	Unit 2 - SDA Inlet	USEPA Method 17	Particulate	1/28/04			(1)
7	Unit 2 - SDA Inlet	USEPA Method 17	Particulate	1/28/04	15:00	16:03	
4	Unit 2 - SDA Inlet	Method 6C	SO2	1/28/04	10:01	11:01	
5	Unit 2 - SDA Inlet	Method 6C	SO2	1/28/04	11:10	12:10	
6	Unit 2 - SDA Inlet	Method 6C	SO2	1/28/04	12:19	12:54	(1)
7	Unit 2 - SDA Inlet	Method 6C	SO2	1/28/04	15:00	16:00	
1	Unit 2 Stack	USEPA Method 13B	Total Fluorides	1/28/04			(2)
2	Unit 2 Stack	USEPA Method 13B	Total Fluorides	1/28/04	10:02	11:11	
3	Unit 2 Stack	USEPA Method 13B	Total Fluorides	1/28/04	11:24	12:30	
3	Unit 2 Stack	USEPA Method 13B	Total Fluorides	1/28/04			(1)
5	Unit 2 Stack	USEPA Method 13B	Total Fluorides	1/28/04	15:00	16:04	
1	Unit 2 Stack	CTM-027	Ammonia	1/28/04	08:00	09:08	
2	Unit 2 Stack	CTM-027	Ammonia	1/28/04	10:02	11:11	
3	Unit 2 Stack	CTM-027	Ammonia	1/28/04	11:34	12:39	

Notes:
[1] EPA Method 6C - Run 6, EPA Method 13B - Run 4, EPA Method 17 - Run 6 voided to due plant problems.
[2] EPA Method 13B, Run 1 voided. Post-test leak check rate exceeded.

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PROJECT OVERVIEW

Table 1-2:
Summary of Test Results

Source / **Constituent**	**Sampling Method**	**Average Emission**
Unit 2 SDA Inlet		
Sulfur Dioxide (ppmdv), Runs 1-3	EPA M6C	99.8
Sulfur Dioxide F_d-based, (lb/MMBtu), Runs 1-3	EPA M6C/19	0.2026
Sulfur Dioxide F_c-based, (lb/MMBtu), Runs 1-3	EPA M6C/19	0.1965
Sulfur Dioxide (ppmdv), Runs 4-6	EPA M6C	135.6
Sulfur Dioxide F_d-based, (lb/MMBtu), Runs 4-6	EPA M6C/19	0.2771
Sulfur Dioxide F_c-based, (lb/MMBtu), Runs 4-6	EPA M6C/19	0.2718
Particulate (gr/dscf), Runs 1-3	EPA M17	6.025
Particulate F_d-based, (lb/MMBtu), Runs 1-3	EPA M17/19	10.478
Particulate F_c-based, (lb/MMBtu), Runs 1-3	EPA M17/19	10.088
Particulate (gr/dscf), Runs 4-6	EPA M17	5.379
Particulate F_d-based, (lb/MMBtu), Runs 4-6	EPA M17/19	9.563
Particulate F_c-based, (lb/MMBtu), Runs 4-6	EPA M17/19	9.307
Mercury (lb/hr)	Ontario Hydro	6.615E-02
Mercury F_d-based, (lb/MMBtu)	Ontario Hydro/19	2.274E-05
Mercury F_c-based, (lb/MMBtu)	Ontario Hydro/19	2.171E-05
Unit 2 Stack		
Particulate (gr/dscf)	EPA M5	0.0022
Particulate (lb/hr)	EPA M5	11.52
Particulate F_d-based, (lb/MMBtu)	EPA M5/19	0.0041
Particulate F_c-based, (lb/MMBtu)	EPA M5/19	0.0040
Fluoride (lb/hr)	EPA M13B/19	<0.0478
Fluoride F_d-based, (lb/MMBtu)	EPA M13B/19	<1.69E-05
Fluoride F_c-based, (lb/MMBtu)	EPA M13B/19	<1.69E-05
Lead (lb/hr)	EPA M29	2.311E-03
Lead F_d-based, (lb/MMBtu)	EPA M29/19	8.224E-07
Lead F_c-based, (lb/MMBtu)	EPA M29/19	8.087E-07
Mercury (lb/hr)	Ontario Hydro	<2.360E-02
Mercury F_d-based, (lb/MMBtu)	Ontario Hydro/19	<8.532E-06
Mercury F_c-based, (lb/MMBtu)	Ontario Hydro/19	<8.251E-06
Mercury (% Removal)	Ontario Hydro/19	53.5
Ammonia (ppmdv)	CTM-027	0.325
Ammonia (lb/hr)	CTM-027	0.564
Ammonia F_d-based, (lb/MMBtu)	CTM-027/19	0.0002
Ammonia F_d-based, (lb/MMBtu)	CTM-027/19	0.0002

Notes:
1. The mass emission rate (lb/MMBtu) presented in the above table for all test parameters was calculated using a dry fuel factor (F_d) of 9,851 dscf/MMBtu and a carbon-based fuel factor (F_c) of 1,837 scf/MMBtu.
2. Total mercury emission results are shown on above table. A speciated breakdown of the mercury emissions is contained in Section 2 of the report.
3. Percent removal efficiency was calculated based on the units of F_d-based lb/MMBtu.

PROJECT MANAGER'S COMMENTS

Ontario Hydro Test Results

Each Ontario Hydro sampling train consists of five (5) sample fractions. These fractions, starting from the sampling nozzle, consist of:

1. 0.1N HNO_3 (Front-half Rinse)
2. Filter
3. KCl (Impingers 1 through 3)
4. HNO_3-H_2O_2 (Impinger 4)
5. KMnO4 (Impingers 5 through 7)

An aliquot of each reagent and an unused filter are placed in pre-cleaned sample containers and labeled as Reagent Blanks. In addition, a sampling train is prepared, taken to the respective sampling location, leak-checked and allowed to remain at the sampling location a duration comparable to the length of a sampling run. The train is then recovered and each of the five fractions listed above are labeled as a Field Train Blanks.

Laboratory results indicated elevated mercury levels in the Fraction 4 (HNO_3-H_2O_2, Elemental Mercury Fraction) of the Reagent Blank and the Field Train Blanks (SDA Inlet and Stack) [Appendix G].

The mercury concentration in the remaining four sample fractions of the Reagent and Field Blanks were at acceptable levels or below the method detection limit.

The Ontario Hydro Method maximum allowable blank adjustment, outlined in Section 13.41, is based on the following criteria:

1. 10% of the measured regent blank value (6.20 ug) or,
2. Ten (10) times the method detection limit of 0.005 ug (0.05 ug), whichever is less.

The numbers indicated in the parentheses are applicable to fraction 4 (HNO_3-H_2O_2).

In accordance with the above criteria a maximum blank correction of 0.05 ug was applied to the fraction 4 (HNO3-H2O2) data and these results are shown in this report. Review of the laboratory, sampling and recovery procedures indicates that the elevated mercury present in fraction 4 of the samples was most likely attributed to the HNO_3-H_2O_2 reagent and present prior to testing. Therefore, in allowing a maximum blank value of 0.05 ug the results may show an emission rate biased higher than those present in the flue gas stream.

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Based on the above information, applying a correction to the fraction 4 portion of the sample train equivalent to the fraction 4 value of the respective Field Blank Trains is recommended (i.e., SDA Inlet = 35.8 ug and Stack = 22.6 ug).

Following this modified blank correction procedure the average total mercury emissions (F_d-based lb/MMBtu) at the SDA Inlet and Stack would be 1.426E-05 and 5.434E-07, respectively. This calculates to an average removal efficiency of 97.0%.

RESULTS

Table 2-1:
Unit 2 – SDA Inlet – Sulfur Dioxide, Run 1 through 3

Run No.	**1**	**2**	**3**	**Average**
Date (2004)	January 27	January 27	January 27	
Start Time	11:35	13:11	14:57	
End Time	12:35	14:11	15:57	
Elapsed Time	1:00	1:00	1:00	
Operating Conditions				
Oxygen-based F-factor (dscf/MMBtu)	9,851	9,851	9,851	**9,851**
Carbon dioxide-based F-factor (dscf/MMBtu)	1,837	1,837	1,837	**1,837**
Capacity factor (hours/year)	8,760	8,760	8,760	**8,760**
Gas Parameters				
Oxygen (dry volume %)	4.1	4.0	4.0	**4.0**
Carbon dioxide (dry volume %)	15.6	15.5	15.4	**15.5**
Actual water vapor in gas (% by volume)	7.88	6.81	6.50	**7.06**
Volumetric flow rate, actual (acfm)	985,459	983,592	983,917	**984,323**
Volumetric flow rate, standard (scfm)	639,139	632,012	634,453	**635,201**
Volumetric flow rate, dry standard (dscfm)	588,774	588,994	593,203	**590,324**
Sulfur Dioxide (SO_2) Results				
Concentration (ppmdv)	101.9	75.3	122.2	**99.8**
Mass Emission Rate (lb/hr)	598.5	442.7	723.2	**588.1**
Mass Emission Rate (ton/year)	2,622	1,939	3,168	**2,576**
Mass Emission Rate - F_d-based (lb/MMBtu)	0.2077	0.1527	0.2475	**0.2026**
Mass Emission Rate - F_c-based (lb/MMBtu)	0.1999	0.1481	0.2417	**0.1965**

RESULTS

Table 2-2:
Unit 2 – SDA Inlet – Sulfur Dioxide, Run 4 through 6

Run No.	**4**	**5**	**7**	**Average**
Date (2004)	January 28	January 28	January 28	
Start Time	10:01	11:10	15:00	
End Time	11:01	12:10	16:00	
Elapsed Time	1:00	1:00	1:00	
Operating Conditions				
Oxygen-based F-factor (dscf/MMBtu)	9,851	9,851	9,851	**9,851**
Carbon dioxide-based F-factor (dscf/MMBtu)	1,837	1,837	1,837	**1,837**
Capacity factor (hours/year)	8,760	8,760	8,760	**8,760**
Gas Parameters				
Oxygen (dry volume %)	4.2	4.1	4.2	**4.1**
Carbon dioxide (dry volume %)	15.1	15.2	15.4	**15.2**
Actual water vapor in gas (% by volume)	7.05	6.89	6.56	**6.84**
Volumetric flow rate, actual (acfm)	966,174	956,170	968,672	**963,672**
Volumetric flow rate, standard (scfm)	632,018	632,876	632,315	**632,403**
Volumetric flow rate, dry standard (dscfm)	587,468	589,246	590,807	**589,174**
Sulfur Dioxide (SO_2) Results				
Concentration (ppmdv)	144.8	124.4	137.6	**135.6**
Mass Emission Rate (lb/hr)	848.7	731.1	811.3	**797.0**
Mass Emission Rate (ton/year)	3,717	3,202	3,553	**3,491**
Mass Emission Rate - F_d-based (lb/MMBtu)	0.2969	0.2527	0.2817	**0.2771**
Mass Emission Rate - F_c-based (lb/MMBtu)	0.2931	0.2498	0.2725	**0.2718**

RESULTS

Table 2-3:
Unit 2 – SDA Inlet – Particulate Matter, Runs 1 through 3

Run No.		**1**	**2**	**3**	**Average**
Date (2004)		Jan 27	Jan 27	Jan 27	
Start Time (approx.)		11:35	13:11	14:57	
Stop Time (approx.)		12:44	14:18	16:04	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,851	9,851	9,851	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,837	1,837	1,837	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	4.2	3.8	4.0	**4.0**
CO_2	Carbon dioxide (dry volume %)	15.6	15.8	15.6	**15.7**
T_s	Sample temperature (°F)	315	322	319	**318**
B_w	Actual water vapor in gas (% by volume)	7.88	6.81	6.50	**7.06**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	985,459	983,592	983,917	**984,323**
Q_s	Volumetric flow rate, standard (scfm)	639,139	632,012	634,453	**635,201**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	588,774	588,994	593,203	**590,324**
Particulate Results					
C_{sd}	Particulate Concentration (gr/dscf)	5.3389	7.1792	5.5577	**6.0253**
$E_{lb/hr}$	Particulate Rate (lb/hr)	26,952	36,256	28,268	**30,492**
$E_{T/yr}$	Particulate Rate (Ton/yr)	118,051	158,802	123,813	**133,555**
E_{Fd}	Particulate Rate - F_d-based (lb/MMBtu)	9.4060	12.3524	9.6756	**10.4780**
E_{Fc}	Particulate Rate - F_c-based (lb/MMBtu)	8.9842	11.9281	9.3524	**10.0882**

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RESULTS

Table 2-4:
Unit 2 – SDA Inlet – Particulate Matter, Runs 4 through 6

Run No.		4	5	7	Average
Date (2004)		Jan 28	Jan 28	Jan 28	
Start Time (approx.)		10:00	11:10	15:00	
Stop Time (approx.)		11:03	12:16	16:03	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,851	9,851	9,851	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,837	1,837	1,837	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	4.3	4.5	4.2	**4.3**
CO_2	Carbon dioxide (dry volume %)	15.2	15.0	15.4	**15.2**
T_s	Sample temperature (°F)	308	300	310	**306**
B_w	Actual water vapor in gas (% by volume)	7.05	6.89	6.56	**6.84**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	966,174	956,170	968,672	**963,672**
Q_s	Volumetric flow rate, standard (scfm)	632,018	632,876	632,315	**632,403**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	587,468	589,246	590,807	**589,174**
Particulate Results					
C_{sd}	Particulate Concentration (gr/dscf)	6.2515	6.0481	3.8358	**5.3785**
$E_{lb/hr}$	Particulate Rate (lb/hr)	31,489	30,557	19,431	**27,159**
$E_{T/yr}$	Particulate Rate (Ton/yr)	137,922	133,840	85,108	**118,957**
E_{Fd}	Particulate Rate - F_d-based (lb/MMBtu)	11.0801	10.8505	6.7579	**9.5628**
E_{Fc}	Particulate Rate - F_c-based (lb/MMBtu)	10.7967	10.5848	6.5387	**9.3067**

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RESULTS

Table 2-5: Unit 2 – SDA Inlet – Mercury (Ontario Hydro)

Run No.		1	2	3	Average
Date (2004)		Jan 27	Jan 27	Jan 27	
Start Time (approx.)		11:30	14:58	18:14	
Stop Time (approx.)		13:36	17:57	20:26	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,851	9,851	9,851	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,837	1,837	1,837	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	4.0	4.2	4.3	**4.2**
CO_2	Carbon dioxide (dry volume %)	15.7	15.6	15.6	**15.6**
T_s	Sample temperature (°F)	311	315	310	**312**
B_w	Actual water vapor in gas (% by volume)	7.18	7.47	6.91	**7.19**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	993,457	986,276	989,118	**989,617**
Q_s	Volumetric flow rate, standard (scfm)	647,181	639,188	645,156	**643,841**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	600,693	591,450	600,596	**597,580**
Total Mercury Results					
$E_{lb/hr}$	Rate (lb/hr)	5.427E-02	7.865E-02	6.553E-02	**6.615E-02**
$E_{T/yr}$	Rate (Ton/yr)	2.377E-01	3.445E-01	2.870E-01	**2.897E-01**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	1.834E-05	2.733E-05	2.255E-05	**2.274E-05**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	1.762E-05	2.610E-05	2.141E-05	**2.171E-05**
Particulate Bound Mercury Results					
$E_{lb/hr}$	Rate (lb/hr)	3.458E-02	4.405E-02	4.110E-02	**3.991E-02**
$E_{T/yr}$	Rate (Ton/yr)	1.514E-01	1.929E-01	1.800E-01	**1.748E-01**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	1.169E-05	1.530E-05	1.414E-05	**1.371E-05**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	1.122E-05	1.462E-05	1.343E-05	**1.309E-05**
Oxidized Mercury Results					
$E_{lb/hr}$	Rate (lb/hr)	1.751E-04	4.127E-04	4.040E-04	**3.306E-04**
$E_{T/yr}$	Rate (Ton/yr)	7.671E-04	1.808E-03	1.770E-03	**1.448E-03**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	5.920E-08	1.434E-07	1.391E-07	**1.139E-07**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	5.686E-08	1.370E-07	1.320E-07	**1.086E-07**
Elemental Mercury Results					
$E_{lb/hr}$	Rate (lb/hr)	1.951E-02	3.419E-02	2.403E-02	**2.591E-02**
$E_{T/yr}$	Rate (Ton/yr)	8.547E-02	1.498E-01	1.052E-01	**1.135E-01**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	6.596E-06	1.188E-05	8.269E-06	**8.914E-06**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	6.335E-06	1.135E-05	7.851E-06	**8.511E-06**

[1] The elemental mercury (HNO_3-H_2O_2 fraction) was calculated using the maximum allowable blank value of (0.05 ug) which is ten (10) times the laboratory detection limit of 0.005 ug.

RESULTS

Table 2-6:
Unit 2 – Stack – Particulate Matter

Run No.		1	2	3	Average
Date (2004)		Jan 27	Jan 27	Jan 27	
Start Time (approx.)		08:00	10:35	13:08	
Stop Time (approx.)		10:07	12:43	15:20	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,851	9,851	9,851	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,837	1,837	1,837	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	5.4	5.0	4.6	**5.0**
CO_2	Carbon dioxide (dry volume %)	14.0	14.7	14.9	**14.5**
T_s	Sample temperature (°F)	226	228	235	**229**
B_w	Actual water vapor in gas (% by volume)	10.76	10.68	10.52	**10.65**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	900,538	897,667	896,953	**898,386**
Q_s	Volumetric flow rate, standard (scfm)	689,974	685,607	677,997	**684,526**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	615,732	612,366	606,699	**611,599**
Particulate Results					
C_{sd}	Particulate Concentration (gr/dscf)	0.0018	0.0024	0.0024	**0.0022**
$E_{lb/hr}$	Particulate Rate (lb/hr)	9.32	12.57	12.68	**11.52**
$E_{T/yr}$	Particulate Rate (Ton/yr)	40.82	55.07	55.54	**50.47**
E_{Fd}	Particulate Rate - F_d-based (lb/MMBtu)	0.0034	0.0044	0.0044	**0.0041**
E_{Fc}	Particulate Rate - F_c-based (lb/MMBtu)	0.0033	0.0043	0.0043	**0.0040**

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RESULTS

Table 2-7: Unit 2 – Stack - Fluoride

Run No.		2	3	5	Average
Date (2004)		Jan 28	Jan 28	Jan 28	
Start Time (approx.)		10:02	11:24	15:00	
Stop Time (approx.)		11:11	12:30	16:04	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,851	9,851	9,851	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,837	1,837	1,837	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	5.2	4.9	4.8	**5.0**
CO_2	Carbon dioxide (dry volume %)	14.3	14.7	14.8	**14.6**
T_s	Sample temperature (°F)	235	226	222	**227**
B_w	Actual water vapor in gas (% by volume)	8.51	8.92	9.18	**8.87**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	870,686	867,477	867,526	**868,563**
Q_s	Volumetric flow rate, standard (scfm)	661,986	668,606	672,322	**667,638**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	605,644	608,958	610,603	**608,402**
Hydrogen Fluoride (HF) Results [1]					
C_{sd}	HF Concentration (ppmdv)	<0.0258	<0.0201	<0.0298	**<0.0253**
$E_{lb/hr}$	HF Rate (lb/hr)	<0.0487	<0.0381	<0.0567	**<0.0478**
$E_{T/yr}$	HF Rate (Ton/yr)	<0.2134	<0.1668	<0.2485	**<0.2096**
E_{Fd}	HF Rate - Fd-based (lb/MMBtu)	<1.76E-05	<1.34E-05	<1.98E-05	**<1.69E-05**
E_{Fc}	HF Rate - Fc-based (lb/MMBtu)	<1.72E-05	<1.30E-05	<1.92E-05	**<1.65E-05**

[1] The "less than" sign indicates that the sample was below the laboratory minimum detection limit of 0.06 mg/liter. The minimum detection limit was used in the calculations.

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RESULTS

Table 2-8:
Unit 2 – Stack – Lead

Run No.		**1**	**2**	**3**	**Average**
Date (2004)		Jan 27	Jan 27	Jan 27	
Start Time (approx.)		08:00	10:35	13:08	
Stop Time (approx.)		10:07	12:43	15:20	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,851	9,851	9,851	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,837	1,837	1,837	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	5.4	5.0	4.6	**5.0**
CO_2	Carbon dioxide (dry volume %)	14.0	14.7	14.9	**14.5**
T_s	Sample temperature (°F)	226	228	235	**229**
B_w	Actual water vapor in gas (% by volume)	10.76	10.68	10.52	**10.65**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	900,538	897,667	896,953	**898,386**
Q_s	Volumetric flow rate, standard (scfm)	689,974	685,607	677,997	**684,526**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	615,732	612,366	606,699	**611,599**
Lead Results - Total					
$E_{lb/hr}$	Rate (lb/hr)	4.712E-03	5.092E-04	1.711E-03	**2.311E-03**
$E_{T/yr}$	Rate (Ton/yr)	2.064E-02	2.230E-03	7.495E-03	**1.012E-02**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	1.694E-06	1.795E-07	5.938E-07	**8.224E-07**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	1.673E-06	1.732E-07	5.796E-07	**8.087E-07**

RESULTS

Table 2-9:
Unit 2 – Stack – Mercury (Ontario Hydro)

Run No.		**1**	**2**	**3**	**Average**
Date (2004)		Jan 27	Jan 27	Jan 27	
Start Time (approx.)		11:30	14:58	18:14	
Stop Time (approx.)		13:39	17:54	20:23	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,851	9,851	9,851	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,837	1,837	1,837	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	5.0	4.7	4.8	**4.8**
CO_2	Carbon dioxide (dry volume %)	14.9	14.8	14.8	**14.8**
T_s	Sample temperature (°F)	215	222	232	**223**
B_w	Actual water vapor in gas (% by volume)	10.64	10.23	10.51	**10.46**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	843,739	846,892	885,409	**858,680**
Q_s	Volumetric flow rate, standard (scfm)	651,187	653,047	672,266	**658,833**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	581,926	586,245	601,600	**589,924**
Total Mercury Results					
$E_{lb/hr}$	Rate (lb/hr)	<2.083E-02	<2.326E-02	<2.672E-02	**<2.360E-02**
$E_{T/yr}$	Rate (Ton/yr)	<9.126E-02	<1.019E-01	<1.170E-01	**<1.034E-01**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	<7.727E-06	<8.404E-06	<9.465E-06	**<8.532E-06**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	<7.357E-06	<8.208E-06	<9.187E-06	**<8.251E-06**
RE	Removal Efficiency (%) Fd-based (lb/MMBtu)	57.9%	54.2%	48.4%	**53.5%**
Particulate Bound Mercury Results					
$E_{lb/hr}$	Rate (lb/hr)	<2.040E-06	<2.052E-06	<2.112E-06	**<2.068E-06**
$E_{T/yr}$	Rate (Ton/yr)	<8.933E-06	<8.988E-06	<9.250E-06	**<9.057E-06**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	<7.564E-10	<7.414E-10	<7.482E-10	**<7.487E-10**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	<7.202E-10	<7.241E-10	<7.262E-10	**<7.235E-10**
Oxidized Mercury Results					
$E_{lb/hr}$	Rate (lb/hr)	<4.079E-05	<4.104E-05	8.447E-05	**<5.544E-05**
$E_{T/yr}$	Rate (Ton/yr)	<1.787E-04	<1.798E-04	3.700E-04	**<2.428E-04**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	<1.513E-08	<1.483E-08	2.993E-08	**<1.996E-08**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	<1.440E-08	<1.448E-08	2.905E-08	**<1.931E-08**
Elemental Mercury Results					
$E_{lb/hr}$	Rate (lb/hr)	2.081E-02	2.324E-02	2.663E-02	**2.356E-02**
$E_{T/yr}$	Rate (Ton/yr)	9.116E-02	1.018E-01	1.166E-01	**1.032E-01**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	7.719E-06	8.397E-06	9.435E-06	**8.517E-06**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	7.349E-06	8.200E-06	9.157E-06	**8.236E-06**

[1] Less than symbol indicates that one or more factions (oxidized mercury) were below the laboratory minimum detection limit. Any fraction below the minimum detection limit was calculated using a value of 0.5 times the non-detect value.
[2] Removal efficiency calculate using F_d-based (lb/MMBtu)
[3] The elemental mercury (HNO_3-H_2O_2 fraction) was calculated using the maximum allowable blank value of (0.05 ug) which is ten (10) times the laboratory detection limit of 0.005 ug.

RESULTS

Table 2-10:
Unit 2 – Stack - Ammonia

Run No.		**1**	**2**	**3**	**Average**
Date (2004)		Jan 28	Jan 28	Jan 28	
Start Time (approx.)		08:00	10:02	11:34	
Stop Time (approx.)		09:08	11:11	12:39	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,851	9,851	9,851	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,837	1,837	1,837	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	5.0	5.1	4.9	**5.0**
CO_2	Carbon dioxide (dry volume %)	14.4	14.4	14.6	**14.5**
T_s	Sample temperature (°F)	221	237	227	**228**
B_w	Actual water vapor in gas (% by volume)	7.20	8.99	8.74	**8.31**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	952,145	917,860	910,351	**926,785**
Q_s	Volumetric flow rate, standard (scfm)	739,165	695,434	699,865	**711,488**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	685,981	632,929	638,684	**652,531**
Ammonia (NH_3) Results					
C_{sd}	Ammonia Concentration (ppmdv)	0.3656	0.3027	0.3068	**0.3250**
$E_{lb/hr}$	Ammonia Rate (lb/hr)	0.6647	0.5079	0.5194	**0.5640**
$E_{T/yr}$	Ammonia Rate (Ton/yr)	2.9114	2.2245	2.2748	**2.4702**
E_{Fd}	Ammonia Rate - Fd-based (lb/MMBtu)	0.0002	0.0002	0.0002	**0.0002**
E_{Fc}	Ammonia Rate - Fc-based (lb/MMBtu)	0.0002	0.0002	0.0002	**0.0002**

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DESCRIPTION OF INSTALLATION

PROCESS DESCRIPTION

The Jacksonville Electric Northside Generating Station Unit 2 consists of a 300 MW circulating fluidized bed (CFB) boiler a lime-based spray dryer absorber (SDA) and a pulse jet fabric filter (PJFF).

The SDA has sixteen independent dual-fluid atomizers. The fabric filter has eight isolatable compartments. The control system also uses reagent preparation and byproduct handling subsystems. The SDA byproduct solids/fly ash collected by the PJFF is pneumatically transferred from the PJFF hoppers to either the Unit 2 fly ash silo or the Unit 2 AQCS recycle bin. Fly ash from the recycle bin is slurried and reused as the primary reagent by the SDA spray atomizers. The reagent preparation system converts quicklime (CaO), which is delivered dry to the station, into a hydrated lime [$Ca(OH)_2$] slurry, which is fed to the atomizers as a supplemental reagent.

The testing reported in this document was performed at the Unit 2 SDA Inlet and Stack locations.

A schematic of the process indicating sampling locations is shown in Figure 3-1.

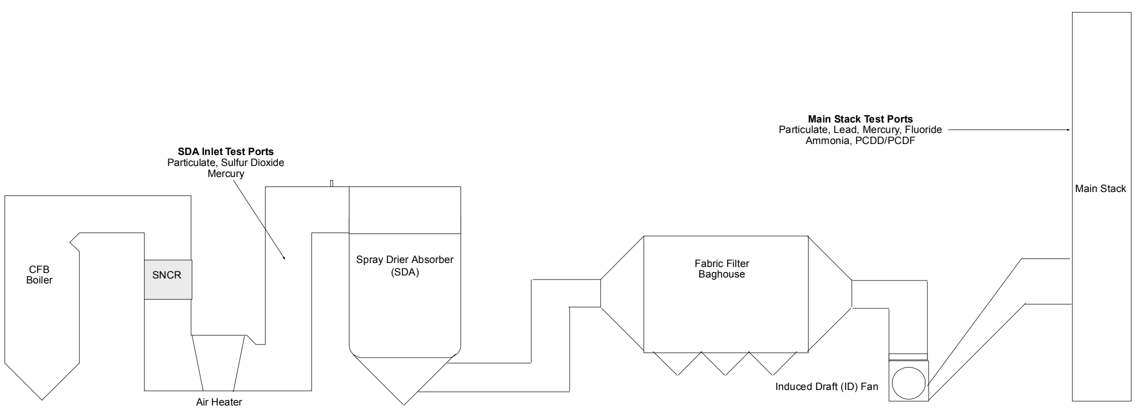


Figure 3-1: Process Schematic

DESCRIPTION OF INSTALLATION

DESCRIPTION OF SAMPLING LOCATION(S)

Sampling point locations were determined according to EPA Method 1.

Table 3-1 outlines the sampling point configurations. Figure 3-3 and 3-3 illustrate the sampling points and orientation of sampling ports for each of the sources tested in the program.

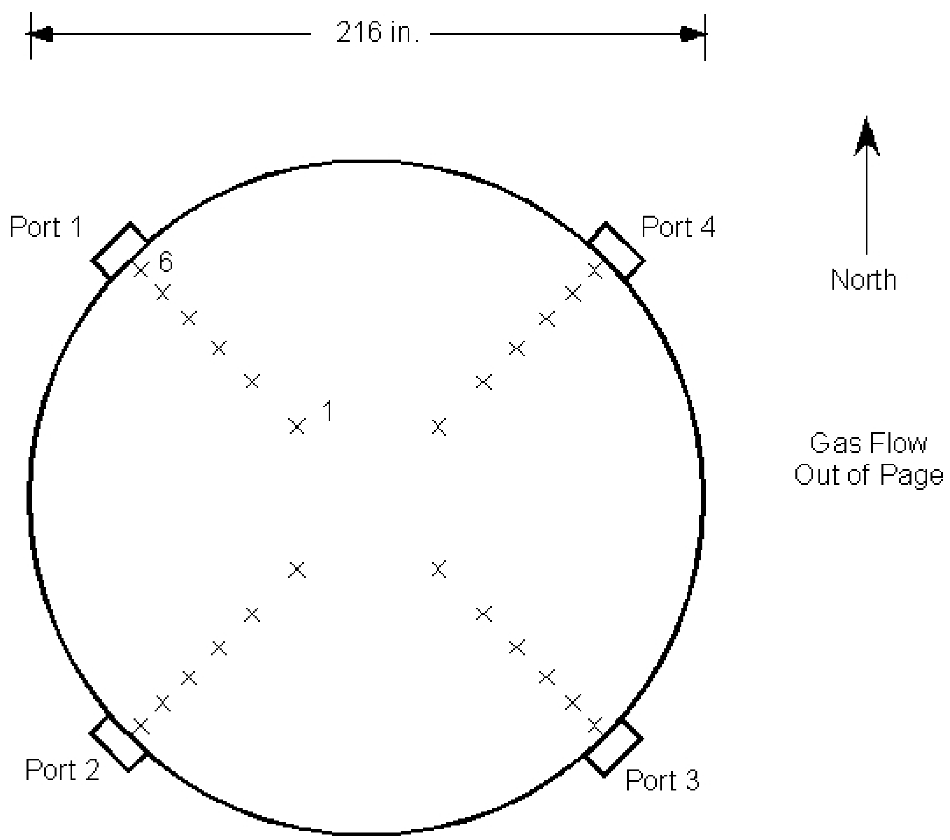
Table 3-1:
Sampling Points

Location	Constituent	Method	Run No.	Ports	Points per Port	Minutes per Point	Total Minutes	Figure
Unit 2 SDA Inlet	SO2	6C	1-7	1	1	60[1]	60	N/A
Unit 2 SDA Inlet	Particulate	17	1-7	4	6	2.5	60	3-1
Unit 2 SDA Inlet	Mercury	OH[2]	1-3	4	6	5	120	3-1
Unit 2 Stack	Particulate	5	1-3	4	3	10	120	3-2
Unit 2 Stack	Fluoride	13B	1-5	4	3	5	60	3-2
Unit 2 Stack	Lead	29	1-3	4	3	10	120	3-2
Unit 2 Stack	Mercury	OH[2]	1-3	4	3	10	120	3-2
Unit 2 Stack	Ammonia	CTM-027	1-3	4	3	5	60	3-2

[1] Sulfur Dioxide was sampled from a single point in the duct. Readings were collected at one-second intervals by the computer based data acquisition system and reported as one-minute averages.
[2] Mercury was determined using the Ontario Hydro method.

DESCRIPTION OF INSTALLATION

DESCRIPTION OF SAMPLING LOCATION (CONTINUED)



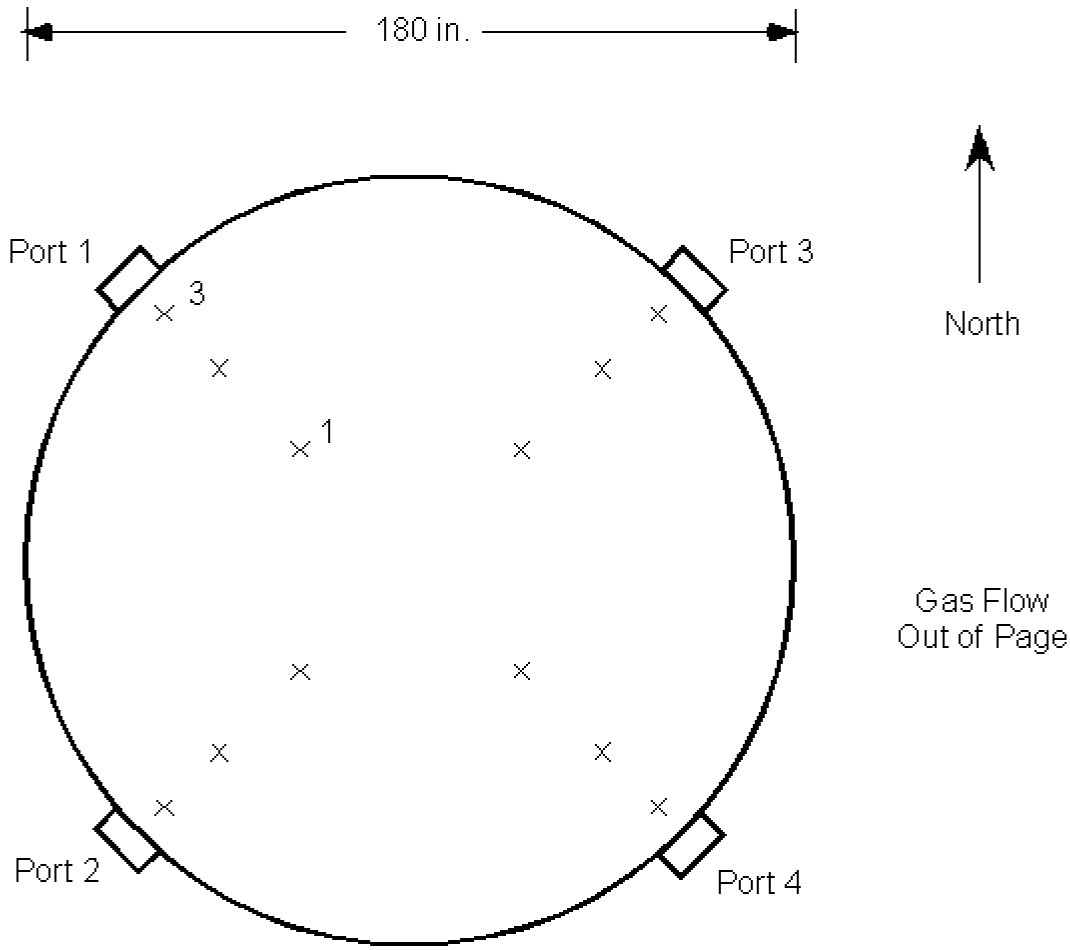
Sampling Point	Port to Point Distance (in.)
1	76.9
2	54.0
3	38.2
4	25.5
5	14.5
6	4.5

Diameters to upstream disturbance: >2.0 Limit: 2.0 (minimum)
Diameters to downstream disturbance: >0.5 Limit: 0.5 (minimum)

Figure 3-2: SDA Inlet Sampling Point Determination (EPA Method 1)

DESCRIPTION OF INSTALLATION

DESCRIPTION OF SAMPLING LOCATION (CONTINUED)



Sampling Point	Port to Point Distance (in.)
1	53.3
2	26.3
3	7.9

Diameters to upstream disturbance: >8.0 — Limit: 2.0 (minimum)
Diameters to downstream disturbance: >2.0 — Limit: 0.5 (minimum)

Figure 3-3: Stack Sampling Point Determination (EPA Method 1)

METHODOLOGY

Clean Air Engineering followed procedures as detailed in U.S. Environmental Protection Agency (EPA) Methods 1, 2, 3A, 4, 5, 6C, 13B, 23, 29, Conditional Test Method CTM-027 and the Ontario Hydro Method. The following table summarizes the methods and their respective sources.

Table 4-1:
Summary of Sampling Procedures

Title 40 CFR Part 60 Appendix A	
Method 1	"Sample and Velocity Traverses for Stationary Sources"
Method 2	"Determination of Stack Gas Velocity and Volumetric Flow Rate (Type S Pitot Tube)"
Method 3A	"Determination of Oxygen and Carbon Dioxide Concentrations in Emissions from Stationary Sources (Instrumental Analyzer Procedure)"
Method 4	"Determination of Moisture Content in Stack Gases"
Method 5	"Determination of Particulate Emissions from Stationary Sources"
Method 6C	"Determination of Sulfur Dioxide Emissions from Stationary Sources (Instrumental Analyzer Procedure)"
Method 13B	"Determination of Total Fluoride Emissions from Stationary Sources (Specific Ion Electrode Method)"
Method 23	"Determination of Polychlorinated Dibenzo-p-Dioxins and Polychlorinated Dibenzofurans from Stationary Sources"
Method 29	"Determination of Metals Emissions from Stationary Sources"
Conditional Test Method	
CTM-027	"Procedure for the Collection and Analysis of Ammonia in Stationary Sources."
Draft Methods	
Ontario Hydro	"Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources."

The EPA Methods (1 through 29) appear in detail in Title 40 of the Code of Federal Regulations (CFR). The Conditional Test Method and the Hydro Ontario Method appear in detail on the US EPA Emissions Measurement Center web page. All methods may be found on the World Wide Web at http://www.cleanair.com.

Diagrams of the sampling apparatus and major specifications of the sampling, recovery and analytical procedures are summarized for each method in Appendix A.

Clean Air Engineering followed specific quality assurance and quality control (QA/QC) procedures as outlined in the individual methods and in USEPA "Quality Assurance Handbook for Air Pollution Measurement Systems: Volume III Stationary Source-Specific Methods", EPA/600/R-94/038C. Additional QA/QC methods as prescribed in Clean Air's internal Quality Manual were also followed. Results of all QA/QC activities performed by Clean Air Engineering are summarized in Appendix D.

APPENDIX

ATTACHMENT D

PI Data Summary

JEA Northside Unit 2
Test #2
50 / 50 Blend - Pittsburgh 8 Coal Pet Coke
SUMMARY PI DATA

	Date:	**January 27, 2004**	**January 28, 2004**
	Start:	**1130 hours**	**1000 hours**
	End:	**1530 hours**	**1600 hours**

Substance	Characteristic Being Measured	Values Used in Efficiency Calculation	
Primary Air	Avg. Out A and B, Deg F	102.7	87.5
	Average, deg F	108.0	95.7
	Count	480	480
	Standard Deviation	2.8720	7.0768
Secondary Air	Total SA flow, klb/hr	0.7020	0.61
	Average, Total SA Flow, klb/hr	0.7011	0.63
	Count	240	240
	Standard Deviation	0.0084	0.0458
	Avg. Out A and B, Deg F	103.4	88.65
	Average, deg F	109.7	95.30
	Count	480	480
	Standard Deviation	6.8505	7.4273
Fuel	Total Flow, klb/hr	194.5	195.12
	Average, deg F	194.2	195.18
	Count	240	240
	Standard Deviation	0.3008	0.4515
PAHTR Gas Out	Gas Out, deg F, A train	295.7	288.10
	Gas Out, deg F, B train	309.3	303.83
	Average, deg F	311.1	298.65
	Count	480	480
	Standard Deviation	7.7917	8.2852
SAHTR Gas Out	Gas Out, deg F, A train	288.4	286.55
	Gas Out, deg F, B train	288.2	294.79
	Average, deg F	289.8	282.62
	Count	480	480
	Standard Deviation	11.8296	11.2515
PAH Gas In	Gas In, deg F, A & B train	563.7	575.73
	Average, deg F	572.5	568.58
	Count	240	240
	Standard Deviation	4.8307	4.5239
SAH Gas In	Gas In, deg F A & B train	566.6	579.20
	Average, deg F	575.7	571.83
	Count	240	240
	Standard Deviation	5.0519	4.7635
PAH Air Out	Air Out, deg F A & B train	461.6	464.06
	Average, deg F	470.7	461.60
	Count	240	240
	Standard Deviation	4.0990	3.4760
SA Airheater Air Out	Air Out, deg F A & B train	431.3	441.20
	Average, deg F	434.3	435.22
	Count	240	240
	Standard Deviation	3.12231	3.98815

Substance	Characteristic Being Measured	Values Used in Efficiency Calculation	
Stripper/ Coolers - A, B, C, D	Ash leaving temperature, deg F, A	0.0	0.00
	Ash leaving temperature, deg F, B	0.0	0.00
	Ash leaving temperature, deg F, C	0.0	0.00
	Ash leaving temperature, deg F, D	0.0	0.00
	Average, deg F	0.0	0.00
	Count	480	480
	Standard Deviation	0.0000	0.000
SDA Hopper	Temperature, deg F		
	Average, deg F	210.3	209.95
	Count	240	240
	Standard Deviation	3.9223	6.2670
Limestone Feed Rate 1	Feedrate, feeders 1, 2, 3, klb/hr	72.3	65.25
	Average, klb/hr	66.4	73.0
	Count	240	240
	Standard Deviation	11.6244	3.9721
SO2, in flue Gas	AH inlet, ppm		
	Average, ppm mv	27.1	51.87
	Count	240	240
	Standard Deviation	13.6302	15.4369
Intrex Blower Air Flow	Flow to A, B, C, lb/hr	35896.6	35776.20
	Average, lb/hr	35790.2	35983.87
	Count	1440	1440
	Standard Deviation	98.0315	158.7149
Intrex Seal Pot Blower	PA Flow to Intrex A, B, C, lb/hr	45404.1	45975.88
	Average, lb/hr	44706.3	45157.57
	Count	240	240
	Standard Deviation	1010.0263	972.9776
Intrex Blower Exit Air Temp	Average, deg F	165.8	150.41
	Count	240	240
	Standard Deviation	2.8880	6.2597
Seal Pot Blower Exit Air Temp	Average, deg F	178.3	162.09
	Count	240	240
	Standard Deviation	3.6163	5.4888
Feedwater Temperature to Econ	Average, deg F	484.3	483.53
	Count	240	240
	Standard Deviation	1.1649	0.8814
Feedwater Pressure to Econ	Average, psiG	1533.2	1501.89
	Count	240	240
	Standard Deviation	5.8658	19.6988
(DSH)SH-1 Spray Flow	Average, klb/hr	19.1	22.82
	Count	240	240
	Standard Deviation	2.2703	4.1563

JEA Northside Unit 2
Test #2
50 / 50 Blend - Pittsburgh 8 Coal Pet Coke
SUMMARY PI DATA

Substance	Characteristic Being Measured	Values Used in Efficiency Calculation	
SH-1 Spray Temperature	Average, deg F	303.0	295.14
	Count	240	240
	Standard Deviation	1.8619	4.2962
SH-1 Spray Pressure	Average, psiG	2700.6	2699.71
	Count	240	240
	Standard Deviation	8.1842	5.2985
Drum Pressure	Average of three pressure values	2562.8	2561.88
	Average, psiG	2561.5	2561.98
	Count	720	720
	Standard Deviation	8.2880	5.1986
Main Steam Temperature	Average, deg F	1003.5	1002.70
	Count	240.0	240
	Standard Deviation	1.5012	0.7836
Main Steam Pressure	Average of two pressure values	2403.3	998.74
	Average, psiG	2400.7	999.81
	Count	480.0	480
	Standard Deviation	5.5393	1.0825
Reheater Outlet Temperature	Average of three temp values	1008.4	1007.91
	Average, deg F	1007.5	1008.17
	Count	720.0	720
	Standard Deviation	3.5757	1.5791
Reheater Outlet Pressure	Average of two pressure values	567.6	566.6
	Average, psiG	569.1	565.4
	Count	480	480
	Standard Deviation	25.8969	25.6913
CRH Ent Attemp Temp	Average, deg F	604.0	599.83
	Count	240.0	240
	Standard Deviation	4.8862	7.7452
CRH Ent Attemp Press	Average, psiG	568.4	564.91
	Count	240.0	240
	Standard Deviation	6.9791	5.5262
RH Spray Flow	Average, klb/hr	1.4	2.16
	Count	240	240
	Standard Deviation	2.4150	3.0002
RH Spray Temp	Average, deg F	300.9	316.17
	Count	240	240
	Standard Deviation	28.2255	16.4067
RH Spray Pressure	Average, psiG	713.7	708.45
	Count	240	240
	Standard Deviation	24.1003	28.4373

JEA Northside Unit 2
Test #2
50 / 50 Blend - Pittsburgh 8 Coal Pet Coke
SUMMARY PI DATA

Substance	Characteristic Being Measured	Values Used in Efficiency Calculation	
Htr 1 FW Entering Temp	Data	417.6	417
	Data	483.8	484.2
	Average, deg F	451.1	450.25
	Count	480	480
	Standard Deviation	33.2734	33.3245
Htr 1 FW Entering Pressure	Data	1541.9	1521.5
	Data	1541.9	1521.5
	Average, psiG	1533.2	1501.9
	Count	480	480
	Standard Deviation	5.8597	19.6782
Htr 1 FW Leaving Temp	Average, deg F	484.3	483.53
	Count	240	240
	Standard Deviation	1.1649	0.8814
Htr 1 FW Leaving Pressure	Average, psiG	1533.2	1501.9
	Count	240	240
	Standard Deviation	5.8658	19.6988
Htr 1 Extraction Stm Temp	Average, deg F	632.7	630.3
	Count	240	240
	Standard Deviation	2.3422	1.1165
Htr 1 Extraction Stm Pressure	Average, psiG	572.0	568.2
	Count	240	240
	Standard Deviation	6.7983	5.5608
Htr 1 Drain Temp	Average, deg F	423.1	422.3
	Count	240	240
	Standard Deviation	0.9820	0.8009
Htr 1 Drain Pressure	Average, psiG	572.0	568.2
	Count	240.0	240
	Standard Deviation	6.7983	5.5608
Feedwater to Econ	Pressure, psiG	1556.6	1536.4
	Temperature, deg F	483.8	484.2
	Density, lb / cu. ft.	0.01990	0.0199
Primary Air to SC A	Total of three flow values	47.6	48.2
	Average, k lb/hr	47.0	47.7
	Count	240	240
	Standard Deviation	0.2949	0.3281
Primary Air to SC B	Total of three flow values	10.3	10.3
	Average, k lb/hr	10.3	10.3
	Count	240	240
	Standard Deviation	0.0412	0.0656
Primary Air to SC C	Total of three flow values	14.3	14.5
	Average, k lb/hr	14.1	14.3
	Count	240	240
	Standard Deviation	0.1	0.1073

JEA Northside Unit 2
Test #2
50 / 50 Blend - Pittsburgh 8 Coal Pet Coke
SUMMARY PI DATA

Substance	Characteristic Being Measured	Values Used in Efficiency Calculation	
Primary Air to SC D	Total of three flow values	46.6	46.8
	Average, k lb/hr	46.0	45.9
	Count	240	240
	Standard Deviation	0.4491	1.5559
Combustion Air Flow into PAH (hot), lb/hr	Total of fourteen flow values	13878.8	14104.5
	Average, k lb/hr	13853.4	14054.1
	Count	240	240
	Standard Deviation	55.7703	51.5375
Combustion Air Flow bypassing PAH (cold), lb/hr	Total of four flow values	53.9	54.9
	Average, k lb/hr	53.2	53.9
	Count	240	240
	Standard Deviation	0.2761	0.6130
Total air Flow, klb/hr	Average, k lb/hr	2393.5	2382.7
	Count	240	240
	Standard Deviation	7.8346	11.5825

ATTACHMENT E

Abbreviation List - Refer to Section 1.2

ATTACHMENT F

Isolation Valve List

Hole #	Description	Approximate Location	Closed (Yes / No)			
			13-Jan-04	14-Jan-04	15-Jan-04	16-Jan-04
37	RHA to CRH	Next to Heat 1	closed	closed	closed	closed
Use Digital Readout	MS Bypass to CRH (Upstream)	Next to Heater 1	closed	closed	closed	closed
38	Desup Wtr from BFP Disch to MS Bypass		closed	closed	closed	closed
Bare Pipe	Heater 1 ~~Running~~ Vent	On Side of Heater 1	closed	closed	closed	closed
Bare Pipe	Heater 1 Relief Vent	Top of Heater 1	closed	closed	closed	closed
49	HRH Bypass to Condenser (Upstream)	Bypass line upstream of valve	closed	closed	closed	closed
50	Desup Wtr from BFP Disch to HRH Byp	Vertical Pipe near HRH Bypass	closed	closed	closed	closed
1 / 25	Htr 1 Dump to Cond	Up/Downstream of Valve	closed	closed	closed	closed
33	Aux Steam Header (GRAY Valve) 337	Platform Overhead	closed	closed	closed	closed
55	CRH Line Drains - common line	Below Turbine	closed	closed	~~open~~ closed	closed
56	CRH Line Drains - common line	Below Turbine	closed	closed	closed	closed
57	CRH Line Drains - North	Below Turbine	closed	closed	closed	closed
58	CRH Line Drains - South	Below Turbine	closed	closed	closed	closed
60	MS Line Drain	Below Turbine	closed	closed	closed	closed
61	MS Line Drain	Below Turbine	closed	closed	closed	closed
#1	Extraction Drain	Below Turbine	closed	closed	closed	closed
	Heat Soak Valve SA330	Below Turbine	closed	closed	closed	closed

#1 Heater shell Drain leaking small amount

Cycle Isolation Checklist

Hole #	Description	Approximate Location	Temp Check
Mezzanine Level			
35	DA Pegging Steam (Upstream)	Next to Heater 1	
36	DA Pegging Steam (Downstream)	Next to Heater 1	
34	DA Pegging Steam Line Drain	Next to Heater 1	
37	RHA to CRH	Next to Heater 1	
39	MS Bypass to CRH (Upstream)	Over railing by Heater 1	
Use Digital Readout	MS Bypass to CRH (Downstream)	Next to Heater 1	
38	Desup Wtr from BFP Disch to MS Bypass	Near railing by Heater 1	
Bare Pipe	Heater 1 Running Vent	On Side of Heater 1	
Bare Pipe	Heater 1 Relief Vent	Top of Heater 1	
Visual	Heater 1 FW Bypass	Directly above Heater 1	
Bare Pipe	Heater 2 Running Vent	On Side of Heater 2	
Bare Pipe	Heater 2 Relief Vent	Top of Heater 2	
Visual	Heater 2 FW Bypass	Directly above Heater 2	
41	Aux Steam to Unit 3 CRH	Against wall - stairs near Htr 5	
40	Aux Steam from Unit 3 CRH	Against wall - stairs near Htr 5	
42	MS to SSH	Platform (overhead)	
43	SSR Bypass Line	Platform (overhead)	
44	Aux Steam Supply Line to SSR	Vertical Pipe near Platform	
Gauge	SSH Pressure	Board on Platform	
45	Heater 4 Running Vent	Side of Heater 4	
Bare Pipe	Heater 4 Relief Vent	Top of Heater 4	
Visual	Heater 4 FW Bypass	Directly above Heater 4	
46	Heater 5 Vent	Side of Heater 5	
47	Heater 5 Vent	Side of Heater 5	
Bare Pipe	Heater 5 Relief Vent	Top of Heater 5	
Visual	Heater 5 FW Bypass	Directly above Heater 5	
48	CBP Disch to BFP Suction	To the side of Heater 5	
Visual	Heater 6 FW Bypass	Near Condenser Wall	
19	BDV to Cond	Near Condenser Wall (right side)	
20	RFDV (Ventilator Valve) to Cond	Bare Pipe near Cond Wall (R/S)	
21	Equalizer Valve to Cond (CRV-1)	Bare Pipe near Cond Wall (R/S)	
22	Equalizer Valve to Cond (CRV-2)	Bare Pipe near Cond Wall (R/S)	
12	MS SV Below Seat Drains to Cond	Below MS Stop Valves	
14	MS SV Below Seat Drains to Cond	Below MS Stop Valves	
52	MS SV Above Seat Drains to Cond	Below MS Stop Valves	
53	MS SV Above Seat Drains to Cond	Below MS Stop Valves	
13	Stm Lead Drains	Near Condenser Wall (R/S)	
16	Stm Lead Drains	Near Condenser Wall (R/S)	
17	Stm Lead Drains	Near Condenser Wall (R/S)	
18	Stm Lead Drains	Near Condenser Wall (R/S)	

Cycle Isolation Checklist

Hole #	Description	Approximate Location	Temp Check
15	CRV Drain Lines	Near HRH Line	
23	CRV Drain Lines	Hear HRH Line	
49	HRH Bypass to Condenser (Upstream)	Bypass line upstream of valve	
DCS	HRH Bypass to Condenser (Downstream)	Control Room	
50	Desup Wtr from BFP Disch to HRH Byp	Vertical Pipe near HRH Bypass	
Visual	SDBFP Recirc to DA	Near HRH Bypass Line	
Visual	MDBFP Recirc to DA	Near HRH Bypass Line	
	Condenser Vacuum		

Ground Floor

Hole #	Description	Approximate Location	Temp Check
24	TDV to Cond (SS Dump)	Into Condenser (use platform)	
7	CRH Drain Hdr 1	Hdr into Cond on Left Side	
8	MS Drain Hdr 2	Hdr into Cond on Left Side	
6	Extraction Drain Hdr 3	Hdr into Cond on Left Side	
10	Drain Hdr 4	Hdr into Cond on Right Side	
9	Drain Hdr 5	Hdr into Cond on Right Side	
11	Steam Lead Drains	Bare Pipe - Side of Condenser	
51	BAC Return to Condenser (CV-4)	U/S of CV-4	
Double Isolate	Hotwell Makeup		
	Polisher Drains	Near Condensate Polishing Sys	
	Bitter Water Pump Off	Near Condensate Polishing Sys	Yes / No
	Unit 2 Fill Pump Off	Near Condensate Polishing Sys	Yes / No
1 / 25	Htr 1 Dump to Cond	Up/Downstream of Valve	/
2	Htr 6 Dump to Cond	Upstream of Valve	
3 / 26	Htr 2 Dump to Cond	Up/Downstream of Valve	/
4 / 27	Htr 4 Dump to Cond	Up/Downstream of Valve	/
5 / 28	Htr 5 Dump to Cond	Up/Downstream of Valve	/
29	Aux Stm to CRH Warm. (U/S of Check Vlv)	Platform Overhead	
30	Aux Stm to CRH Warm. (D/S of Check Vlv)	Platform Overhead	
31	Aux Steam to/from Unit 3 CRH	Platform Overhead	
32	Aux Steam to SSH	Platform Overhead	
33	Aux Steam Header Gray Valve	Platform Overhead	
54	HRH Line Drains	Below Turbine	
59	HRH Line Drains	Below Turbine	
55	CRH Line Drains - common line	Below Turbine	
56	CRH Line Drains - common line	Below Turbine	
57	CRH Line Drains - North	Below Turbine	
58	CRH Line Drains - South	Below Turbine	
60	MS Line Drain	Below Turbine	
61	MS Line Drain	Below Turbine	
	#1 Extr Drain Heat Soak Valve	Below Turbine	

Cycle Isolation Checklist

Hole #	Description	Approximate Location	Temp Check
	Hotwell Make-Up Valves		
	Boiler Blow Down Valve		
	Valve SA 328 (turbine soak line)		
	Auxiliary Steam Supply to Seal Steam System		
	Valve 331 Auxiliary Steam from Cold RH		
	Reheat Attemperator		
	Heater #1 Continuous Vent		
	Heater #2 Continuous Vent		
	Heater #4 Continuous Vent		
	Heater #5 Continuous Vent		

ATTACHMENT G

Fuel Analyses - 50/50 Blend Pet Coke and Pittsburgh 8 Coal

JEA Northside Unit2
Test #2
50/50 Blend Pet Coke and Pittsburgh 8 Coal
SUMMARY FUEL ANALYSES

Fuel	Unit #2				
	Jan. 27, 2004				
Time	1L & 2L 11:30	1L & 2L 12:30	1L & 2L 13:30	1L & 2L 14:30	1L & 2L 15:30
Proximate Analysis					
Moisture, wt% (±0.25)	7.24	7.81	7.64	7.04	6.96
Ash, wt% (±0.49)	5.45	6.25	5.54	5.68	5.83
Volatile, wt% (±1.0)	36.90	36.65	37.99	30.63	37.84
Fixed Carbon, wt% (±1.0)	50.41	49.29	48.83	56.66	49.38
Ultimate Analysis					
Carbon, wt% (±2.51)	75.62	73.42	72.95	73.90	76.37
Hydrogen, wt% (±0.30)	4.24	4.13	4.49	4.43	4.71
Nitrogen, wt% (±0.17)	1.50	1.58	1.39	1.44	1.45
Sulfur, wt% (±0.009)	4.68	5.61	6.73	6.19	3.51
Moisture, wt% (±0.25)	7.24	7.81	7.64	7.04	6.96
Ash, wt% (±0.49)	5.45	6.25	5.54	5.68	5.83
Oxygen, wt% (±2.51)	1.27	1.21	1.26	1.33	1.18
Higher Heating, Btu/lb (±107 Btu/lb)	13,361	13,457	13,371	13,391	13,567
Total Chlorine, wt% (±200 ug/g)	0.06	0.07	0.17	0.09	0.07
Total Fluorine, wt% (±15 ug/g)	0.000	0.000	0.000	0.000	0.000
Total Mercury, ug/g (±0.031 ug/g)	0.003	0.001	0.003	0.002	0.002
Total Lead, ug/g (±9 ug/g)	0.000	0.002	0.002	0.000	0.000
Moisture (oven), wt% (±1.0)	7.24	7.81	7.64	7.04	6.96
Ash elemental analysis					
SiO_2, wt% (±0.65)	0.55	0.51	0.58	0.66	0.71
Al_2O_3, wt% (±0.98)	58.89	63.91	60.76	62.89	67.44
Fe_2O_3, wt% (±1.44)	5.59	6.73	8.08	6.19	5.39
CaO, wt% (±4.74)	22.56	14.73	17.81	15.96	13.75
MgO, wt% (±1.25)	3.22	2.72	2.83	3.09	2.77
Na_2O, wt% (±3.70)	5.47	6.36	6.04	6.55	6.04
K_2O, wt% (±4.25)	3.28	4.54	3.32	4.01	3.35
Ti_2O, wt% (±1.52)	0.42	0.51	0.57	0.64	0.55
Particulate size distribution					
Particulate Left Mesh, 1/2", wt%	14.11	8.60	8.32	14.05	8.99
Particulate Left Mesh, 1/4", wt%	19.73	18.26	21.18	16.37	17.71
Particulate Left Mesh, #4, wt%	9.31	7.24	6.88	7.69	6.59
Particulate Left Mesh, #8, wt%	18.58	18.87	19.29	18.76	19.69
Particulate Left Mesh, #14, wt%	11.84	15.35	14.96	13.94	14.98
Particulate Left Mesh, #28, wt%	16.91	20.47	18.37	18.23	21.77
Particulate Left Mesh, #50, wt%	5.96	7.10	6.76	6.80	6.81
Particulate Left Mesh, #100, wt%	1.97	2.50	2.49	2.55	2.08
Bottom, wt%	0.75	0.59	0.76	0.69	0.41

The values obtained are averages of tests performed on two separate composite samples for each day and each hour

JEA Northside Unit2
Test #2
50/50 Blend Pet Coke and Pittsburgh 8 Coal
SUMMARY FUEL ANALYSES

Fuel	Unit #2				
	Jan. 28, 2004				
Time	1L & 2L 10:00	1L & 2L 11:00	1L & 2L 12:00	1L & 2L 15:00	1L & 2L 16:00
Proximate Analysis					
Moisture, wt% (±0.25)	6.95	7.18	7.01	6.84	7.29
Ash, wt% (±0.49)	6.02	6.86	7.28	4.80	4.63
Volatile, wt% (±1.0)	38.02	36.95	33.35	37.82	37.96
Fixed Carbon, wt% (±1.0)	49.02	49.01	52.37	50.55	50.13
Ultimate Analysis					
Carbon, wt% (±2.51)	71.58	75.23	74.65	75.38	71.55
Hydrogen, wt% (±0.30)	4.73	5.00	4.37	4.26	4.67
Nitrogen, wt% (±0.17)	1.90	1.49	1.59	1.66	1.53
Sulfur, wt% (±0.009)	7.63	2.99	3.77	5.66	9.27
Moisture, wt% (±0.25)	6.95	7.18	7.01	6.84	7.29
Ash, wt% (±0.49)	6.02	6.86	7.28	4.80	4.63
Oxygen, wt% (±2.51)	1.21	1.27	1.34	1.40	1.07
Higher Heating, Btu/lb (±107 Btu/lb)	12,971	13,563	13,445	13,340	12,936
Total Chlorine, wt% (±200 ug/g)	0.17	0.15	0.06	0.08	0.11
Total Fluorine, wt% (±15 ug/g)	0.000	0.000	0.000	0.000	0.000
Total Mercury, ug/g (±0.031 ug/g)	0.002	0.003	0.006	0.003	0.003
Total Lead, ug/g (±9 ug/g)	0.006	0.003	0.001	0.000	0.000
Moisture (oven), wt% (±1.0)	6.95	7.18	7.01	6.84	7.29
Ash elemental analysis					
SiO_2, wt% (±0.65)	0.54	0.48	1.08	1.11	0.68
Al_2O_3, wt% (±0.98)	60.13	64.01	67.55	59.31	66.96
Fe_2O_3, wt% (±1.44)	9.82	7.52	6.47	6.30	6.35
CaO, wt% (±4.74)	15.25	13.67	13.85	20.82	12.21
MgO, wt% (±1.25)	2.97	2.75	2.54	2.88	2.41
Na_2O, wt% (±3.70)	6.05	6.49	4.65	5.39	7.53
K_2O, wt% (±4.25)	4.62	4.47	3.44	3.65	3.30
Ti_2O, wt% (±1.52)	0.62	0.60	0.43	0.51	0.55
Particulate size distribution					
Particulate Left Mesh, 1/2", wt%	11.11	14.84	15.29	9.15	8.96
Particulate Left Mesh, 1/4", wt%	15.79	18.35	17.06	17.18	15.09
Particulate Left Mesh, #4, wt%	7.47	7.89	7.05	6.09	6.82
Particulate Left Mesh, #8, wt%	19.14	17.13	16.65	18.20	18.65
Particulate Left Mesh, #14, wt%	15.67	12.63	15.04	15.47	18.06
Particulate Left Mesh, #28, wt%	20.37	17.67	17.87	23.57	22.00
Particulate Left Mesh, #50, wt%	6.71	7.53	7.01	5.92	6.65
Particulate Left Mesh, #100, wt%	2.17	2.56	2.56	3.55	2.07
Bottom, wt%	0.39	0.55	0.56	0.31	0.66

ATTACHMENT H

Limestone Analyses

JEA Northside Unit2
Test #2
50/50 Blend Pet Coke and Pittsburgh 8 Coal
SUMMARY LIMESTONE ANALYSES

Limestone	Test #2 Jan. 27, 2004					
Lab number	32077-01A	32077-02B	32077-03C	32077-04D	32077-05E	Average Values
Date	1/27/2004	1/27/2004	1/27/2004	1/27/2004	1/27/2004	
Time	11:30	12:30	13:30	14:30	15:30	
Compound Analysis						
$CaCO_3$, wt% (±0.41)	91.26	90.18	91.64	92.51	91.39	91.40
$MgCO_3$, wt% (±0.41)	3.17	3.03	2.97	2.82	2.74	2.95
Moisture (oven), wt% (±1.0)	0.53	0.50	0.52	0.47	0.53	0.51
Inerts (subtraction), wt% (±1.0)	5.03	6.29	4.87	4.20	5.33	5.15
Total Chlorine, wt% (±200 ug/g)	0.12	0.11	0.05	0.06	0.13	0.10
Total Fluorine, wt% (±15 ug/g)	0.000	0.000	0.000	0.000	0.000	0.00
Total Mercury, ug/g (±0.031 ug/g)	0.000	0.000	0.000	0.000	0.000	0.00
Total Lead, ug/g (±9 ug/g)	0.000	0.000	0.000	0.000	0.000	0.00
Elemental analysis, AA						
Na, wt% (±0.5 ug/g)	0.01	0.01	0.01	0.01	0.01	0.01
K, wt% (±0.5 ug/g)	0.000	0.01	0.01	0.000	0.000	0.00
Particulate size distribution						
Particulate Left Mesh, #8, wt%	28.03	30.08	43.46	31.92	31.52	33.00
Particulate Left Mesh, #14, wt%	13.52	17.98	10.34	18.11	14.56	14.90
Particulate Left Mesh, #28, wt%	16.38	18.15	10.41	18.86	14.69	15.70
Particulate Left Mesh, #50, wt%	9.82	9.30	8.12	9.85	9.00	9.22
Particulate Left Mesh, #100, wt%	8.02	5.56	5.93	6.14	6.10	6.35
Particulate Left Mesh, #200, wt%	9.45	5.88	8.67	9.82	9.54	8.67
Particulate Left Mesh, #270, wt%	7.42	6.38	8.31	2.60	10.80	7.10
Bottom, wt%	5.86	4.54	3.58	1.56	2.72	3.65
Conversion Fraction	83.46	85.81	85.70	83.27	84.86	84.62

JEA Northside Unit2
Test #2
50/50 Blend Pet Coke and Pittsburgh 8 Coal
SUMMARY LIMESTONE ANALYSES

Limestone	Test #2 Jan. 28, 2004					
Lab number	**32078-01A**	**32078-02B**	**32078-03C**	**32078-04D**	**32078-05E**	**Average Values**
Date	**1/28/2004**	**1/28/2004**	**1/28/2004**	**1/28/2004**	**1/28/2004**	
Time	**10:00**	**11:00**	**12:00**	**15:00**	**16:00**	
Compound Analysis						
$CaCO_3$, wt% (±0.41)	84.83	87.93	86.04	87.88	85.28	86.39
$MgCO_3$, wt% (±0.41)	2.72	3.00	2.78	2.76	2.83	2.82
Moisture (oven), wt% (±1.0)	0.29	0.30	0.29	0.47	0.45	0.36
Inerts (subtraction), wt% (±1.0)	12.16	8.76	10.89	8.89	11.44	10.43
Total Chlorine, wt% (±200 ug/g)	0.03	0.20	0.07	0.05	0.05	0.08
Total Fluorine, wt% (±15 ug/g)	0.000	0.000	0.000	0.000	0.000	0.00
Total Mercury, ug/g (±0.031 ug/g)	0.001	0.002	0.004	0.002	0.004	0.00
Total Lead, ug/g (±9 ug/g)	0.000	0.000	0.000	0.000	0.000	0.00
Elemental analysis, AA						
Na, wt% (±0.5 ug/g)	0.01	0.01	0.01	0.01	0.01	0.01
K, wt% (±0.5 ug/g)	0.000	0.000	0.01	0.000	0.000	0.00
Particulate size distribution						
Particulate Left Mesh, #8, wt%	24.94	28.39	44.25	40.85	39.33	35.55
Particulate Left Mesh, #14, wt%	13.20	11.48	17.67	17.64	15.00	15.00
Particulate Left Mesh, #28, wt%	13.65	12.24	13.38	12.98	13.21	13.09
Particulate Left Mesh, #50, wt%	11.79	12.47	5.92	5.91	14.44	10.11
Particulate Left Mesh, #100, wt%	13.90	15.21	6.54	6.53	6.03	9.64
Particulate Left Mesh, #200, wt%	20.58	12.54	5.33	5.32	6.15	9.98
Particulate Left Mesh, #270, wt%	0.00	4.89	7.83	7.82	2.82	4.67
Bottom, wt%	0.89	1.36	0.79	1.54	1.63	1.24
Conversion Fraction	80.51	79.40	79.03	78.70	77.81	79.09

ATTACHMENT I

Bed Ash Analyses

JEA Northside Unit 2
Test #2
50/50 Blend Pet Coke and Pittsburgh 8 Coal
SUMMARY - BED ASH ANALYSES

Bed Ash	Test #2 Jan. 27, 2004						
Lab Number	**32075-01**	**32075-02**	**32075-03**	**32075-04**	**32075-05**	**32075-06**	**32075-07**
Date	**1/27/2004**	**1/27/2004**	**1/27/2004**	**1/27/2004**	**1/27/2004**	**1/27/2004**	**1/27/2004**
Time	**11:30**	**12:30**	**12:30**	**13:30**	**13:30**	**14:30**	**15:30**
Unburned carbon, wt%	0.01	0.02	0.06	0.01	0.08	0.03	0.02
Compound analysis							
CaSO4, wt% (±0.2)	24.90	15.60	18.90	27.60	20.40	26.40	15.90
Sulfur, wt% (±0.09)	0.94	0.62	0.70	1.04	0.77	1.07	0.65
Ash compound analysis							
SiO2, wt% (±0.65)	2.64	2.12	2.02	1.88	1.83	2.17	1.70
SO3, wt% (±0.98)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fe2O3, wt% (±1.44)	58.97	68.43	70.11	66.97	71.79	68.51	71.79
CaO, wt% (±4.74) (Not Part of Normalization)	20.74	21.38	21.34	21.06	20.96	21.12	21.30
MgO, wt% (±1.25)	32.45	24.42	23.16	24.31	21.90	24.52	22.29
Na2O, wt% (±3.70)	3.71	2.83	2.35	3.28	2.27	3.24	2.13
K2O, wt% (±4.25)	0.87	0.32	0.23	2.30	0.22	0.37	0.19
Vanadium, wt% (±1.0)	0.57	0.63	0.81	0.23	0.69	0.02	0.48
Nickel, wt% (±1.0)	0.80	1.24	1.32	1.03	1.30	1.18	1.43
Elemental analysis, AA							
Na, wt% (±0.5 ug/g)	0.01	0.02	0.02	0.02	0.02	0.02	0.02
K, wt% (±0.5 ug/g)	0.000	0.000	0.000	0.02	0.000	0.000	0.000
Particulate size distribution							
Particulate Left Mesh, 1/2", wt%	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Particulate Left Mesh, #4, wt%	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Particulate Left Mesh, #8, wt%	2.37	21.04	4.25	4.48	4.00	8.04	8.44
Particulate Left Mesh, #14, wt%	5.11	7.15	6.15	6.46	6.19	6.22	6.49
Particulate Left Mesh, #28, wt%	18.24	18.53	18.58	16.70	16.96	18.01	17.69
Particulate Left Mesh, #48, wt%	26.34	19.79	23.28	20.91	23.68	22.58	21.92
Particulate Left Mesh, #100, wt%	34.15	18.11	26.15	25.22	27.26	25.91	24.19
Particulate Left Mesh, #200, wt%	11.99	15.07	19.21	25.64	20.96	17.98	20.22
Bottom, wt%	0.33	0.04	0.18	0.09	0.07	0.16	0.10

JEA Northside Unit 2
Test #2
50/50 Blend Pet Coke and Pittsburgh 8 Coal
SUMMARY - BED ASH ANALYSES

Bed Ash	
Lab Number Date Time	Average Values
Unburned carbon, wt%	0.03
Compound analysis	
CaSO4, wt% (±0.2)	21.39
Sulfur, wt% (±0.09)	0.83
Ash compound analysis	
SiO2, wt% (±0.65)	2.05
SO3, wt% (±0.98)	0.00
Fe2O3, wt% (±1.44)	68.08
CaO, wt% (±4.74) (Not Part of Normalization)	21.13
MgO, wt% (±1.25)	24.72
Na2O, wt% (±3.70)	2.83
K2O, wt% (±4.25)	0.64
Vanadium, wt% (±1.0)	0.49
Nickel, wt% (±1.0)	1.18
Elemental analysis, AA	
Na, wt% (±0.5 ug/g)	0.02
K, wt% (±0.5 ug/g)	0.00
Particulate size distribution	
Particulate Left Mesh, 1/2", wt%	0.00
Particulate Left Mesh, #4, wt%	0.00
Particulate Left Mesh, #8, wt%	7.52
Particulate Left Mesh, #14, wt%	6.25
Particulate Left Mesh, #28, wt%	17.82
Particulate Left Mesh, #48, wt%	22.64
Particulate Left Mesh, #100, wt%	25.85
Particulate Left Mesh, #200, wt%	18.72
Bottom, wt%	0.14

JEA Northside Unit 2
Test #2
50/50 Blend Pet Coke and Pittsburgh 8 Coal
SUMMARY - BED ASH ANALYSES

Bed Ash	Test #2 Jan. 28, 2004						
Lab Number	**32076-01**	**32076-02**	**32076-03**	**32076-04**	**32076-05**	**32076-06**	**32076-07**
Date	**1/28/2004**	**1/28/2004**	**1/28/2004**	**1/28/2004**	**1/28/2004**	**1/28/2004**	**1/28/2004**
Time	**10:00**	**11:00**	**12:00**	**12:00**	**15:00**	**16:00**	**16:00**
Unburned carbon, wt%	0.02	0.01	0.01	0.03	0.01	0.01	0.01
Compound analysis							
CaSO4, wt% (±0.2)	23.10	20.70	24	21.30	20.40	26.70	27.60
Sulfur, wt% (±0.09)	0.86	0.81	0.81	0.78	0.83	1.09	1.11
Ash compound analysis							
SiO2, wt% (±0.65)	1.01	1.97	1.99	1.85	1.78	2.04	1.76
SO3, wt% (±0.98)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fe2O3, wt% (±1.44)	72.10	69.20	69.34	72.60	67.67	70.82	70.61
CaO, wt% (±4.74) (Not Part of Normalization)	21.03	21.24	21.23	20.92	21.13	21.38	21.39
MgO, wt% (±1.25)	23.22	24.83	23.86	21.34	25.93	23.88	23.43
Na2O, wt% (±3.70)	2.01	2.26	2.52	2.11	2.54	1.78	2.10
K2O, wt% (±4.25)	0.20	0.33	0.36	0.25	0.30	0.21	0.30
Vanadium, wt% (±1.0)	0.05	0.49	0.88	0.67	0.65	0.02	0.60
Nickel, wt% (±1.0)	1.41	0.93	1.04	1.19	1.13	1.26	1.20
Elemental analysis, AA							
Na, wt% (±0.5 ug/g)	0.01	0.01	0.02	0.02	0.01	0.01	0.01
K, wt% (±0.5 ug/g)	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Particulate size distribution							
Particulate Left Mesh, 1/2", wt%	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Particulate Left Mesh, #4, wt%	0.13	0.21	0.25	0.31	0.27	0.31	0.22
Particulate Left Mesh, #8, wt%	3.07	4.78	3.77	7.20	11.16	10.20	9.48
Particulate Left Mesh, #14, wt%	4.51	9.23	5.72	6.37	12.11	7.71	6.32
Particulate Left Mesh, #28, wt%	13.55	15.52	17.76	16.71	20.91	19.22	16.63
Particulate Left Mesh, #48, wt%	20.07	21.21	23.03	20.19	19.33	21.18	23.77
Particulate Left Mesh, #100, wt%	28.39	26.52	26.91	22.75	20.86	24.12	26.11
Particulate Left Mesh, #200, wt%	29.85	22.36	22.44	26.32	14.72	17.02	17.34
Bottom, wt%	0.09	0.17	0.13	0.15	0.11	0.14	0.13

JEA Northside Unit 2
Test #2
50/50 Blend Pet Coke and Pittsburgh 8 Coal
SUMMARY - BED ASH ANALYSES

Bed Ash	
Lab Number **Date** **Time**	**Average Values**
Unburned carbon, wt%	0.01
Compound analysis	
CaSO4, wt% (±0.2)	23.40
Sulfur, wt% (±0.09)	0.90
Ash compound analysis	
SiO2, wt% (±0.65)	1.77
SO3, wt% (±0.98)	0.00
Fe2O3, wt% (±1.44)	70.33
CaO, wt% (±4.74) (Not Part of Normalization)	21.19
MgO, wt% (±1.25)	23.78
Na2O, wt% (±3.70)	2.19
K2O, wt% (±4.25)	0.28
Vanadium, wt% (±1.0)	0.48
Nickel, wt% (±1.0)	1.16
Elemental analysis, AA	
Na, wt% (±0.5 ug/g)	0.01
K, wt% (±0.5 ug/g)	0.00
Particulate size distribution	
Particulate Left Mesh, 1/2", wt%	0.00
Particulate Left Mesh, #4, wt%	0.24
Particulate Left Mesh, #8, wt%	7.09
Particulate Left Mesh, #14, wt%	7.42
Particulate Left Mesh, #28, wt%	17.19
Particulate Left Mesh, #48, wt%	21.25
Particulate Left Mesh, #100, wt%	25.09
Particulate Left Mesh, #200, wt%	21.44
Bottom, wt%	0.13

ATTACHMENT J

Fly Ash (Air Heater and PJFF) Analyses

January 27, 2004

JEA Northside Unit 2
Test #2
50/50 Blend Pet Coke and Pittsburgh 8 Coal
SUMMARY FLYASH ANALYSES

Fly Ash	Test #2 Jan. 27, 2004					
Lab Number / Time	32073-05 (Air Heater) 11:30	32073-08 (Air Heater) 12:30	32073-10 (Air Heater) 13:30	32073-12 (Air Heater) 14:30	32073-16 (Air Heater) 15:30	Average Values
Unburned carbon, wt%	1.07	1.05	1.72	2.10	2.49	1.69
Compound analysis						
CaSO4, wt% (±0.2)	26.10	18.90	29.10	29.10	21.60	24.96
Sulfur, wt% (±0.09)	0.91	0.73	1.08	1.17	0.90	0.96
Ash compound analysis						
SiO2, wt% (±0.65)	1.03	0.59	0.85	0.81	0.74	0.80
SO3, wt% (±0.98)	0.00	0.00	0.00	0.00	0.00	0.00
Fe2O3, wt% (±1.44)	73.84	74.81	72.33	72.49	72.53	73.20
CaO, wt% (±4.74) (Not Part of Norm	20.99	21.30	20.76	20.71	21.03	20.96
MgO, wt% (±1.25)	10.14	9.65	10.41	10.60	11.23	10.41
Na2O, wt% (±3.70)	7.76	7.84	8.84	8.92	8.27	8.33
K2O, wt% (±4.25)	5.36	5.36	5.74	6.06	5.51	5.61
Vanadium, wt% (±1.0)	0.76	0.65	0.76	0.02	0.63	0.57
Nickel, wt% (±1.0)	1.10	1.09	1.06	1.11	1.10	1.09
Elemental analysis, AA						
Na, wt% (±0.5 ug/g)	0.04	0.05	0.05	0.05	0.04	0.05
K, wt% (±0.5 ug/g)	0.02	0.02	0.02	0.02	0.02	0.02
Particulate size distribution						
Particulate Left Mesh, #4, wt%	0.33	0.08	0.08	0.00	0.00	0.10
Particulate Left Mesh, #14, wt%	0.17	0.17	0.06	0.46	0.04	0.18
Particulate Left Mesh, #28, wt%	0.12	0.13	0.10	0.29	0.17	0.16
Particulate Left Mesh, #48, wt%	0.21	0.15	0.07	0.29	0.00	0.14
Particulate Left Mesh, #100, wt%	0.33	0.45	0.35	0.75	0.37	0.45
Particulate Left Mesh, #270, wt%	79.58	76.31	75.81	72.30	70.32	74.86
Particulate Left Mesh, #325, wt%	5.16	6.01	5.92	6.58	6.24	5.98
Bottom, wt%	13.74	16.71	17.60	18.96	22.61	17.92

JEA Northside Unit 2
Test #2
50/50 Blend Pet Coke and Pittsburgh 8 Coal
SUMMARY FLYASH ANALYSES

Fly Ash	Test #2 Jan. 27, 2004				
Lab Number / Time	32073-09 (Bag House) 12:30	32073-11 (Bag House) 13:30	32073-13 (Bag House) 14:30	32073-17 (Bag House) 15:30	Average Values
Unburned carbon, wt%	7.17	6.74	6.97	6.96	5.91
Compound analysis					
CaSO4, wt% (±0.2)	39.60	26.10	27.60	18.90	27.43
Sulfur, wt% (±0.09)	1.40	0.90	1.02	0.77	1.01
Ash compound analysis					
SiO2, wt% (±0.65)	0.32	0.20	0.25	0.19	0.35
SO3, wt% (±0.98)	0.00	0.00	0.00	0.00	0.00
Fe2O3, wt% (±1.44)	70.32	74.15	76.04	74.40	73.62
CaO, wt% (±4.74) (Not Part of Norm	21.17	21.22	21.27	20.98	21.16
MgO, wt% (±1.25)	4.98	5.79	5.58	5.92	5.57
Na2O, wt% (±3.70)	13.75	10.81	9.24	10.64	11.11
K2O, wt% (±4.25)	9.75	7.76	6.29	7.55	7.84
Vanadium, wt% (±1.0)	0.44	0.86	2.48	0.85	1.16
Nickel, wt% (±1.0)	0.43	0.43	0.12	0.44	0.35
Elemental analysis, AA					
Na, wt% (±0.5 ug/g)	0.24	0.19	0.18	0.18	0.20
K, wt% (±0.5 ug/g)	0.18	0.15	0.14	0.14	0.15
Particulate size distribution					
Particulate Left Mesh, #4, wt%	0.00	0.00	0.00	0.00	0.00
Particulate Left Mesh, #14, wt%	0.09	0.00	0.00	0.17	0.07
Particulate Left Mesh, #28, wt%	0.00	0.00	0.00	0.00	0.00
Particulate Left Mesh, #48, wt%	0.00	0.00	0.00	0.00	0.00
Particulate Left Mesh, #100, wt%	0.10	0.00	0.00	0.25	0.09
Particulate Left Mesh, #270, wt%	19.11	19.72	19.33	20.35	19.63
Particulate Left Mesh, #325, wt%	25.25	29.75	26.11	22.34	25.86
Bottom, wt%	55.45	50.16	54.56	55.60	53.94

JEA Northside Unit 2
Test #2
50/50 Blend Pet Coke and Pittsburgh 8 Coal
SUMMARY FLYASH ANALYSES

Fly Ash	Test #2 Jan. 28, 2004					
Lab Number / Time	32073-01 (Air Heater) 10:00	32073-03 (Air Heater) 11:00	32073-06 (Air Heater) 12:00	32073-14 (Air Heater) 15:00	32073-18 (Air Heater) 16:00	Average Values
Unburned carbon, wt%	1.73	1.38	1.79	1.61	1.85	1.67
Compound analysis						
CaSO4, wt% (±0.2)	39.60	29.40	33.30	26.70	27.90	31.38
Sulfur, wt% (±0.09)	1.52	1.09	1.26	1.19	1.04	1.22
Ash compound analysis						
SiO2, wt% (±0.65)	1.05	0.80	1.03	0.54	0.69	0.82
SO3, wt% (±0.98)	0.00	0.00	0.00	0.00	0.00	0.00
Fe2O3, wt% (±1.44)	72.87	73.89	73.80	74.60	75.47	74.13
CaO, wt% (±4.74) (Not Part of Norm	21.00	21.10	21.10	21.05	21.07	21.07
MgO, wt% (±1.25)	11.04	10.26	10.19	10.36	10.33	10.44
Na2O, wt% (±3.70)	8.32	8.41	7.94	8.03	7.05	7.95
K2O, wt% (±4.25)	5.51	5.59	5.04	5.46	4.70	5.26
Vanadium, wt% (±1.0)	0.21	0.06	1.00	0.01	0.71	0.40
Nickel, wt% (±1.0)	1.00	1.00	1.01	1.00	1.04	1.01
Elemental analysis, AA						
Na, wt% (±0.5 ug/g)	0.05	0.05	0.05	0.05	0.04	0.05
K, wt% (±0.5 ug/g)	0.02	0.02	0.02	0.02	0.01	0.02
Particulate size distribution						
Particulate Left Mesh, #4, wt%	0.00	0.00	0.13	0.08	0.00	0.04
Particulate Left Mesh, #14, wt%	0.04	0.07	0.11	0.17	0.00	0.08
Particulate Left Mesh, #28, wt%	0.04	0.11	0.09	0.17	0.08	0.10
Particulate Left Mesh, #48, wt%	0.04	0.08	0.12	0.14	0.04	0.08
Particulate Left Mesh, #100, wt%	0.25	0.28	0.37	0.48	0.46	0.37
Particulate Left Mesh, #270, wt%	75.79	77.21	76.17	74.94	77.55	76.33
Particulate Left Mesh, #325, wt%	6.70	6.02	5.88	5.89	5.59	6.02
Bottom, wt%	16.77	16.23	17.13	18.14	15.87	16.83

JEA Northside Unit 2
Test #2
50/50 Blend Pet Coke and Pittsburgh 8 Coal
SUMMARY FLYASH ANALYSES

Fly Ash	Test #2 Jan. 28, 2004					
Lab Number / Time	32073-02 (Bag House) 10:00	32073-04 (Bag House) 11:00	32073-07 (Bag House) 12:00	32073-15 (Bag House) 15:00	32073-19 (Bag House) 16:00	Average Values
Unburned carbon, wt%	7.27	6.68	6.45	6.06	6.13	1.67
Compound analysis						
CaSO4, wt% (±0.2)	30.90	30.60	29.40	29.40	28.10	31.38
Sulfur, wt% (±0.09)	1.21	1.19	1.10	1.18	1.04	1.22
Ash compound analysis						
SiO2, wt% (±0.65)	0.37	0.43	0.32	0.33	0.35	0.82
SO3, wt% (±0.98)	0.00	0.00	0.00	0.00	0.00	0.00
Fe2O3, wt% (±1.44)	71.78	73.66	72.59	73.43	76.35	74.13
CaO, wt% (±4.74) (Not Part of Norm	21.26	20.79	20.89	21.30	20.92	21.07
MgO, wt% (±1.25)	5.88	5.66	6.37	6.78	6.21	10.44
Na2O, wt% (±3.70)	12.28	11.14	11.68	10.82	9.71	7.95
K2O, wt% (±4.25)	8.48	7.94	7.90	7.37	6.63	5.26
Vanadium, wt% (±1.0)	0.81	0.78	0.73	0.84	0.46	0.40
Nickel, wt% (±1.0)	0.41	0.39	0.41	0.45	0.29	1.01
Elemental analysis, AA						
Na, wt% (±0.5 ug/g)	0.23	0.23	0.20	0.17	0.14	0.05
K, wt% (±0.5 ug/g)	0.17	0.18	0.15	0.12	0.10	0.02
Particulate size distribution						
Particulate Left Mesh, #4, wt%	0.00	0.00	0.00	0.00	0.00	0.04
Particulate Left Mesh, #14, wt%	0.01	0.04	0.00	0.00	0.07	0.08
Particulate Left Mesh, #28, wt%	0.00	0.00	0.00	0.00	0.00	0.10
Particulate Left Mesh, #48, wt%	0.00	0.00	0.00	0.00	0.00	0.08
Particulate Left Mesh, #100, wt%	0.31	0.92	0.00	0.00	0.39	0.37
Particulate Left Mesh, #270, wt%	18.92	19.93	17.12	20.02	19.13	76.33
Particulate Left Mesh, #325, wt%	26.72	20.38	30.02	21.26	24.25	6.02
Bottom, wt%	54.04	58.32	51.96	58.72	56.16	16.83

ATTACHMENT K

Ambient Data, Jan. 27, 2004 & Jan. 28, 2004

JEA Northside Unit 2
Test #2
50/50 Blend Pet Coke and Pittsburgh 8 Coal
SUMMARY MET DATA

Date:	**January 27, 2004**	**January 28, 2004**
Start:	**1130 hours**	**1000 hours**
End:	**1530 hours**	**1600 hours**
Characteristic Being Measured	**Values Used in Efficiency Calculation**	
Dry Bulb Temperature, North / South, deg F	64.24	39.96
Count	482	482
Standard Deviation	3.7952	5.8027
Wet Bulb Temperature, North / South, deg F	57.96	43.19
Count	482	482
Standard Deviation	0.9488	6.8152
Atmospheric Pressure, in Hg	29.99	30.23
Atmospheric Pressure, psia	14.7	14.8
Count	5	6
Standard Deviation	0.00841	0.01025

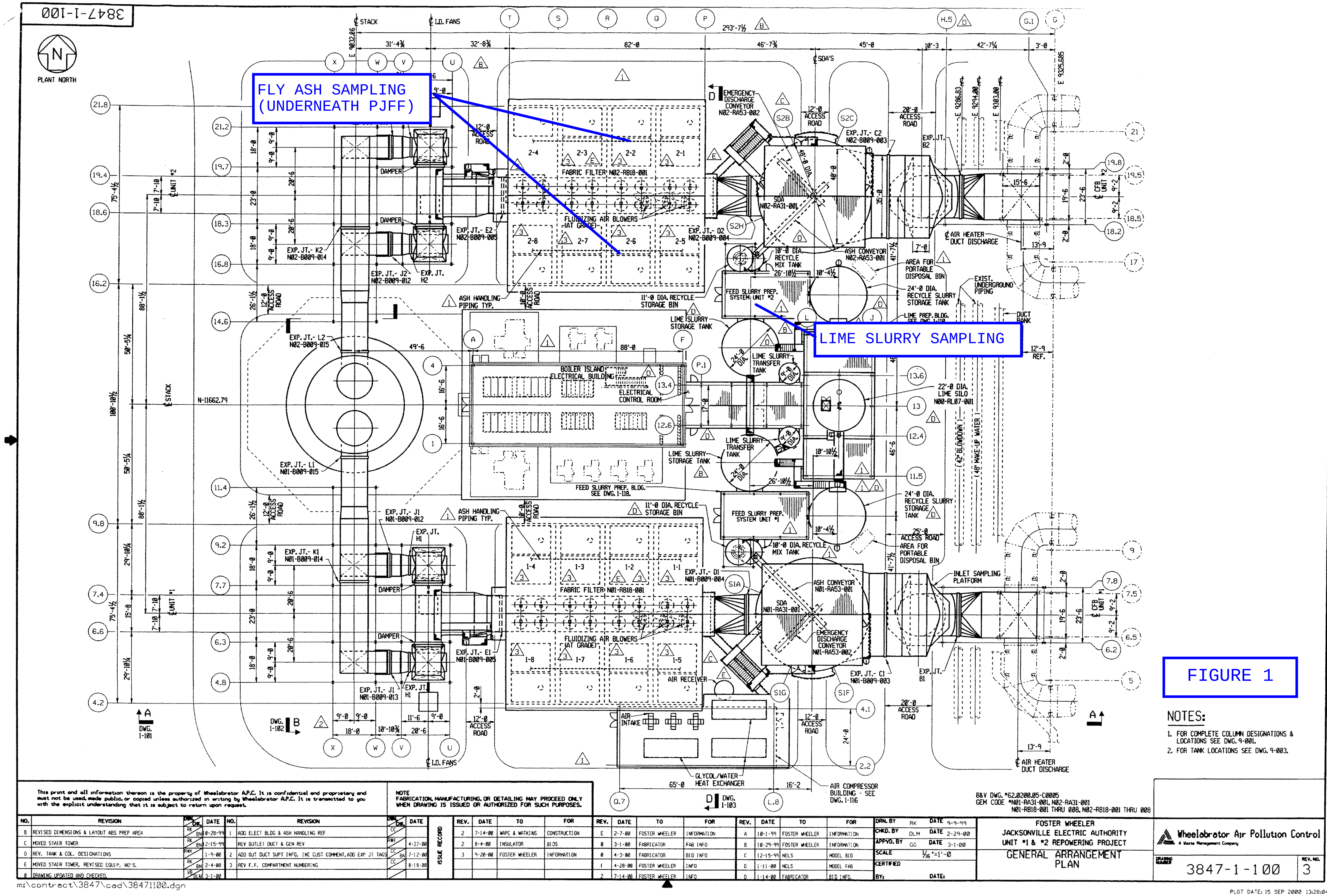
ATTACHMENT L

Ambient Data, Jan. 29, 2004, Jan. 30, 2004, & Jan. 31, 2004

JEA Northside Unit 2
Test #2
50/50 Blend Pet Coke and Pittsburgh 8 Coal
MET DATA PARTIAL LOADS

DATE	TIME	WET BULB, DEG F	DRY BULB, DEG F	PRESSURE, PSIA	RELATIVE HUMIDITY, %
JAN. 31, 2004	12:00 AM	44	51	14.9	56.25
40% LOAD	1:00 AM	45	52	14.9	59.97
	2:00 AM	46	55	14.9	46.59
	3:00 AM	50	58	14.9	56.38
	4:00 AM	49	56	14.9	57.81
JAN. 29/30, 2004	10:00 PM	45	48	14.85	79.63
60% LOAD	11:00 PM	44	46	14.85	85.73
	12:00 PM	43	45	14.85	85.43
	1:00 AM	45	49	14.85	73.60
	2:00 AM	46	50	14.85	74.11
JAN. 29, 2004	3:00 PM	45.0	56	14.85	40.13
80% LOAD	4:00 PM	47.0	62	14.85	30.37
	5:00 PM	47.0	62	14.85	30.37
	6:00 PM	47.5	58	14.85	44.58
	7:00 PM	48.0	56	14.85	57.51

FIGURES



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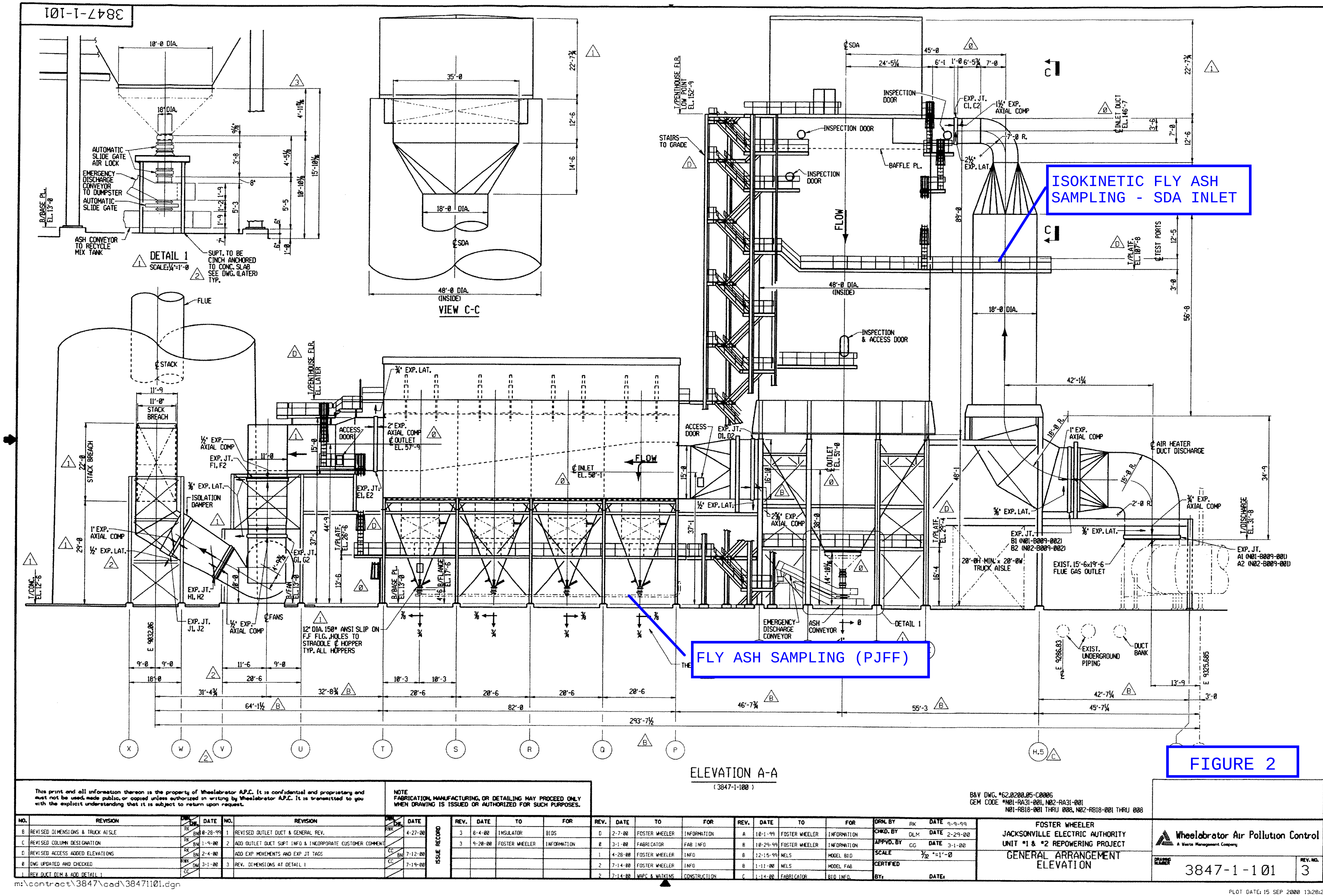
DWG40998 03-MAR-2004 14:47:11



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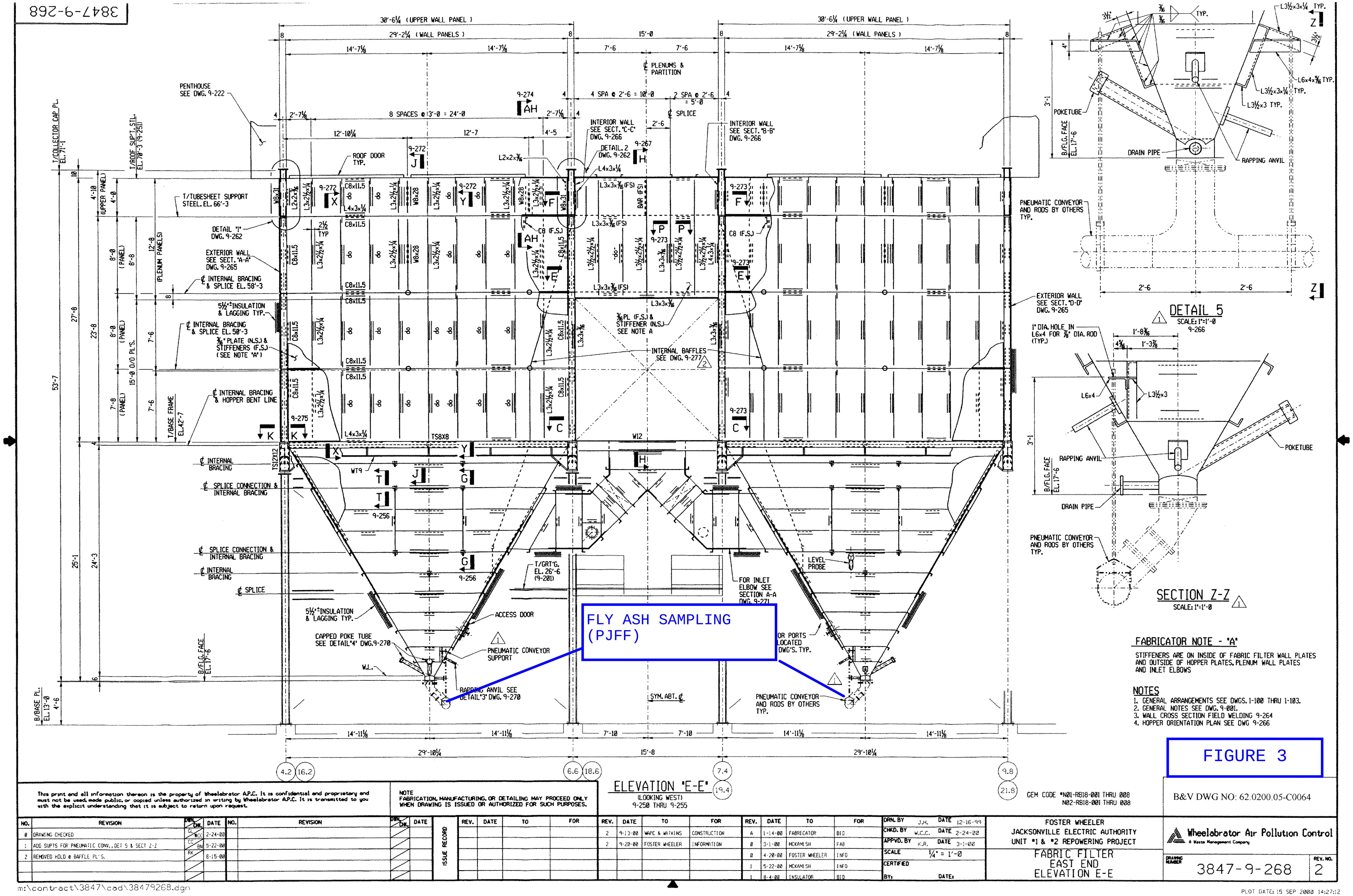

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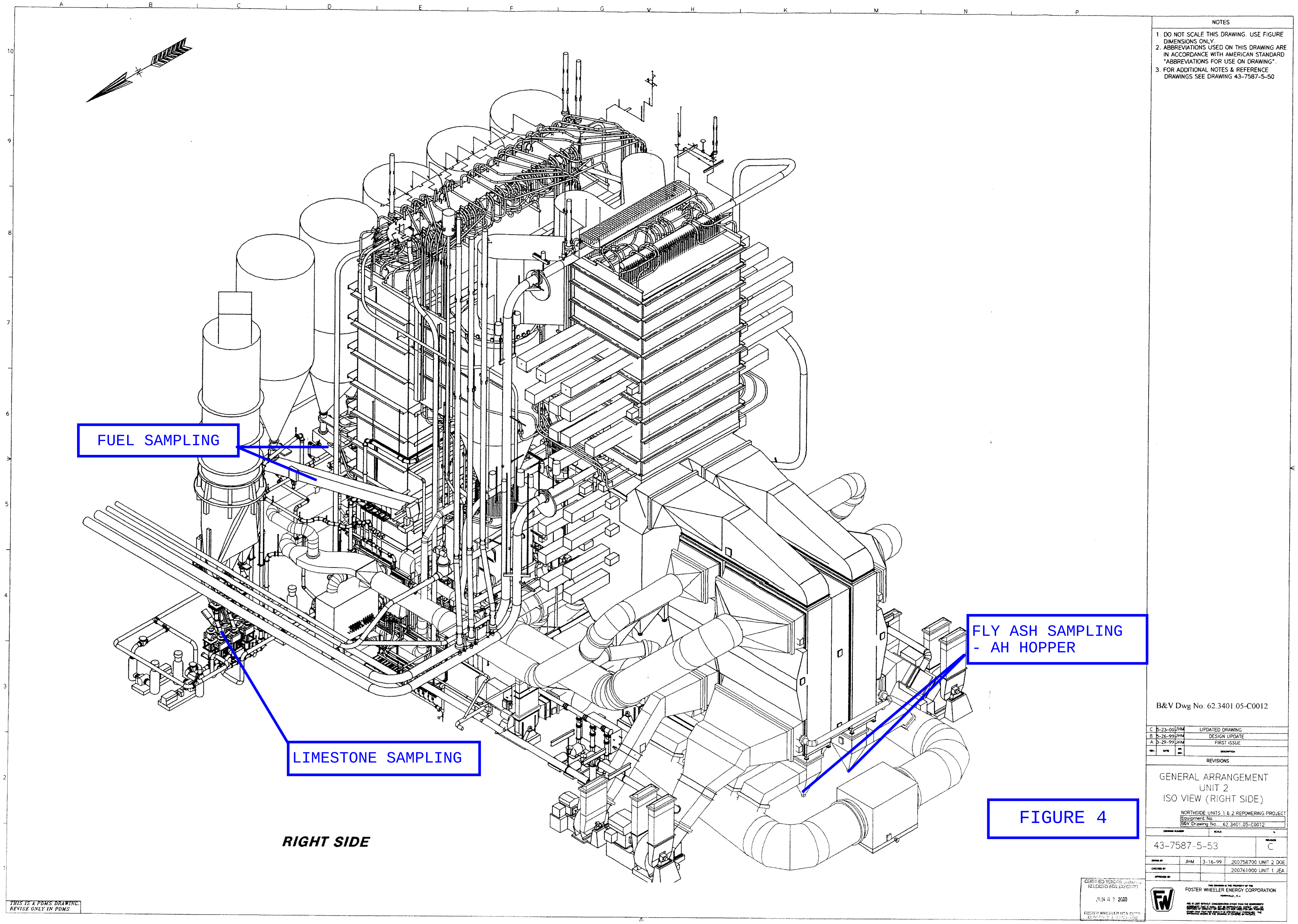
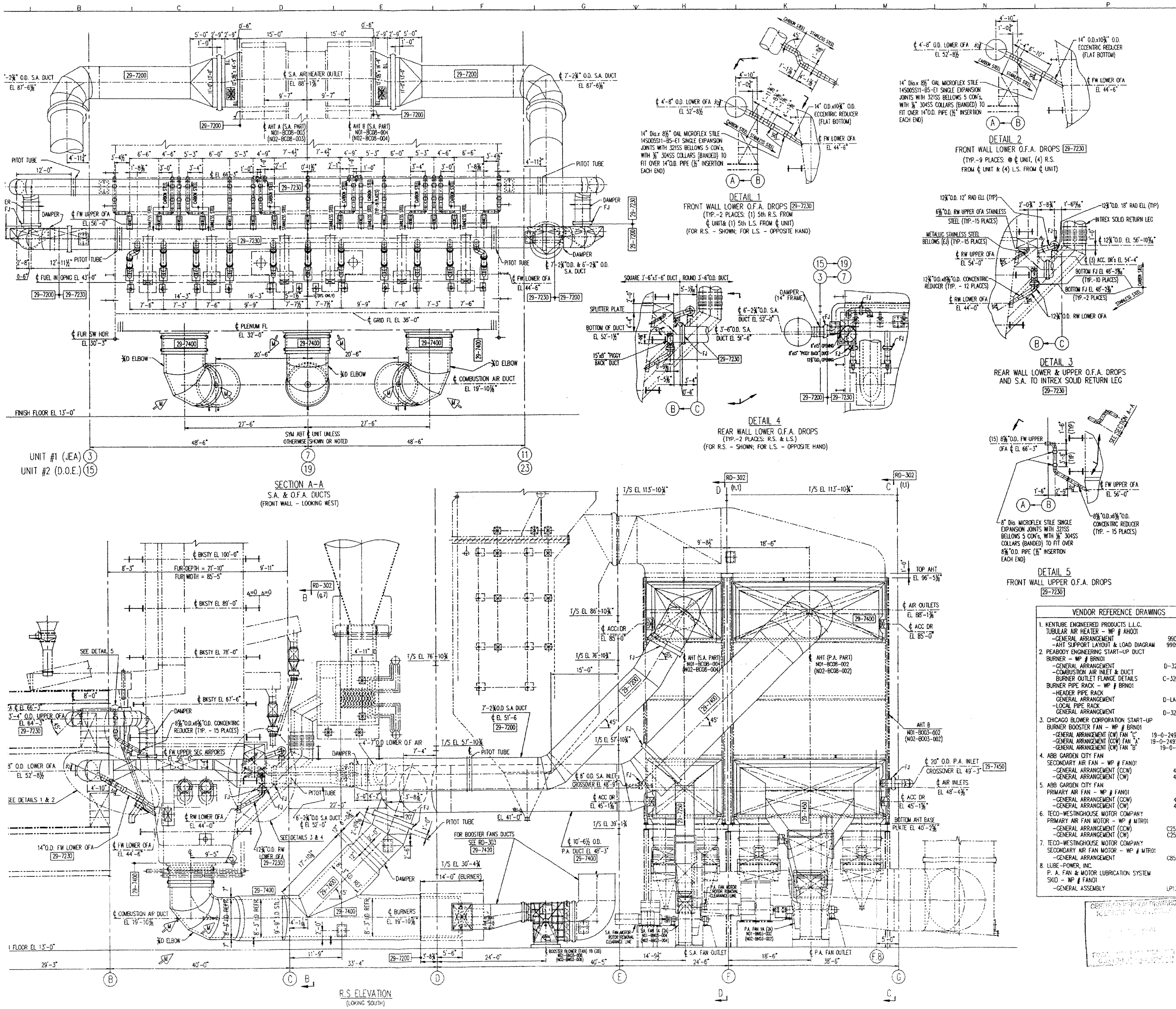


FIGURE 4

DWG40998 03-MAR-2004 14:30:51



NOTES

1. DO NOT SCALE THIS DRAWING. USE FIGURE DIMENSIONS ONLY.
2. ABEREVIATIONS USED ON THIS DRAWING ARE IN ACCORDANCE WITH AMERICAN STANDARD "ABBREVIATIONS FOR USE ON DRAWING".
3. UNLESS OTHERWISE SPECIFIED, ALL CLEARANCE LINES FOR DUCTS AND FLUES SHALL BE AS FOLLOWS:
   a) DUCTS & FLUES - 18", UNLESS NOTED;
   b) AIR HEATERS, FANS & DUST COLLECTORS - 18";
   c) EXP. JOINTS & DAMPERS - 30" FOR A LENGTH OF 24" EITHER SIDE OF JOINT OR DAMPER.
4. FWEC DENOTES FOSTER WHEELER ENERGY CORPORATION WORK TERMINATES; VD- DENOTES VENDOR REF. DWG.
5. ALL DIMENSIONS ARE TO INSIDE OF PLATE UNLESS OTHERWISE NOTED.
6. ALL ROUND MITERED DUCT ELBOWS RADIUS EQUAL ONE DIAMETR OF DUCT OR FLUE (R=1D) UNLESS OTHERWISE NOTED.
7. FOR PLATE THICKNESS, PLATE MATERIAL & EXPANSION JOINT INFORMATION REFER TO FLUE & DUCT ASSEMBLY DRAWINGS BEGINNING WITH DRAWING 43-7587-5-310, WHEN ISSUED.
8. ALL ACCESS DOORS ARE 18"x24"(H).

FWEC REFERENCE DRAWINGS

1. GENERAL ARRANGEMENT CROSS SECTION	43-7587-5-20
2. GENERAL ARRANGEMENT LONGITUDINAL SECTIONS A-A & B-B	43-7587-5-21
3. GENERAL ARRANGEMENT LONGITUDINAL SECTIONS C-C & D-D	43-7587-5-22
4. ARRANGEMENT AUXILLIARY EQUIPMENT SECONDARY AIR, PRIMARY AIR DUCTS PLAN VIEW	43-7587-5-301
5. ARRANGEMENT AUXILLIARY EQUIPMENT SECONDARY AIR, PRIMARY AIR DUCTS SECTIONS B-B, C-C, D-D AND VIEWS	43-7587-5-302
6. ARRANGEMENT AUXILLIARY EQUIPMENT BURNER BOOSTER BLOWERS (FANS) LAYOUT. PLAN VIEW & SECTIONS	43-7587-5-303
7. ARRANGEMENT AUXILLIARY EQUIPMENT BOILER EXIT/AHT & AHT/FWEC TERMINAL FLUE PLAN VIEW @ AHT TOP, R.S. ELEVATION AND VIEWS A-A & B-B	43-7587-5-304
8. ARRANGEMENT AUXILLIARY EQUIPMENT BOILER EXIT/AHT & AHT/FWEC TERMINAL FLUE PLAN VIEWS C-C & @ AHT SUPPORT LEVEL AND DETAILS	43-7587-5-305
9. INSTRUMENT LOCATION PLANS	43-7587-5-6400 THRU 6404, 6406, 6408, 6411, 6413 THRU 6419

VENDOR REFERENCE DRAWINGS

1. KENTUBE ENGINEERED PRODUCTS L.L.C. TUBULAR AIR HEATER - WP # AH001	
-GENERAL ARRANGEMENT	99091-1
-AHT SUPPORT LAYOUT & LOAD DIAGRAM	99091-2
2. PEABODY ENGINEERING START-UP DUCT BURNER - WP # BRN01	
-GENERAL ARRANGEMENT	D-326001
-COMBUSTION AIR INLET & DUCT BURNER OUTLET FLANGE DETAILS	C-326004
BURNER PIPE RACK - WP # BRN01	
-HEADER PIPE RACK GENERAL ARRANGEMENT	D-LATER
-LOCAL PIPE RACK GENERAL ARRANGEMENT	D-326036
3. CHICAGO BLOWER CORPORATION START-UP BURNER BOOSTER FAN - WP # BRN01	
-GENERAL ARRANGEMENT (CW) FAN "C"	19-0-2492-01
-GENERAL ARRANGEMENT (CCW) FAN "A"	19-0-2492-02
-GENERAL ARRANGEMENT (CW) FAN "B"	19-0-2493
4. ABB GARDEN CITY FAN SECONDARY AIR FAN - WP # FAN01	
-GENERAL ARRANGEMENT (CCW)	43092
-GENERAL ARRANGEMENT (CW)	43093
5. ABB GARDEN CITY FAN PRIMARY AIR FAN - WP # FAN01	
-GENERAL ARRANGEMENT (CCW)	43104
-GENERAL ARRANGEMENT (CW)	43105
6. TECO-WESTINGHOUSE MOTOR COMPANY PRIMARY AIR FAN MOTOR - WP # MTR01	
-GENERAL ARRANGEMENT (CCW)	C2534AA
-GENERAL ARRANGEMENT (CW)	C2534AB
7. TECO-WESTINGHOUSE MOTOR COMPANY SECONDARY AIR FAN MOTOR - WP # MTR01	
-GENERAL ARRANGEMENT	C8550AA
8. LUBE-POWER, INC. P. A. FAN & MOTOR LUBRICATION SYSTEM SKID - WP # FAN01	
-GENERAL ASSEMBLY	LP1354-A

REVISIONS

REV.	DATE	DR.	DESCRIPTION
M	03-20-01	AGS	REVISED LOCATION OF RIGHT AND LEFT SIGHT GLASS PORTS AT COMBUSTION AIR DUCTS @ SECTION A-A AND RIGHT SIDE ELEVATION.
L	02-28-01	AGS	DELETED "HOLD" FROM COMBUSTION AIR DUCT AND ADDED (2) ACCESS DOOR AND DIMENSIONS TO IT AS SHOWN AT RIGHT SIDE ELEVATION.
K	07-12-00	AGS	ADDED VENDOR REFERENCE DRAWINGS VRD-8.
J	06-22-00	AGS	REVISED TAG NUMBER FOR BURNER BOOSTER FAN "B", S.A. & P.A. FANS @ R.S. ELEVATION. ADDED FWEC REFERENCE DRAWINGS RD-9. REVISED VENDOR REFERENCE DRAWINGS VRD-3. ADDED VENDOR REFERENCE DRAWINGS: PEABODY BURNER PIPE RACKS DRAWINGS. UPDATED BOOSTER BLOWER INLET & OUTLET DUCTING AND BOOSTER BLOWERS PICTURES ACCORDING TO ACTUAL PURCHASED FANS. PURCHASED FANS @ R.S. ELEVATION. REVISED DIMENSION 24'-0" (WAS 24'-6") FOR BOOSTER BLOWER "B" FROM ℄ TO COLUMN "D" @ R.S. ELEVATION.
H	03-08-00	AGS	REVISED SOME (8 of 15) FRONT WALL UPPER O.F.A. DROPS (8⅝" O.D. PIPE) AT R.S. ELEVATION, SECTION A-A & DETAIL 5.
G	02-08-00	AGS	CORRECTED FWUSA TAG No's FOR Pri. & Sec. AHT PARTS.
F	02-04-00	AGS	ADDED P.A. FAN MOTOR VENDOR REFERENCE DRAWINGS. REVISED START-UP BURNER BOOSTER FAN VENDOR REFERENCE DRAWING NUMBERS. DELETED "HOLD" @ P.A. & S.A. FAN MOTORS & REVISED P.A. & S.A. FAN MOTORS PICTURES AT RIGHT SIDE ELEVATION. ADDED PART No.'s FOR DUCTS.
E	11-24-99	AGS	ADDED NOTE 8. REVISED DIMENSION BETWEEN COLUMNS "F.8" & "G": 5'-0" (WAS 6'-0") @ R.S. ELEVATION. ADDED P.A. FAN VENDOR REFERENCE DRAWING NUMBERS. REVISED P.A. FAN PICTURE TO INCLUDE ACTUAL PURCHASED FAN @ R.S. ELEVATION. ADDED DETAIL 5. REVISED SIZE OF FW UPPER OFA DROPS EXPANSION JOINTS: TOGGLE SECTION WITH (2) TWO METALLIC BELLOWS (WAS (1) ONE FABRIC EJ) @ R.S. ELEVATION & SECTION A-A.
D	11-08-99	AGS	ADDED VENDOR REFERENCE DRAWINGS. ADDED FWEC REFERENCE DRAWINGS No.'s 6, 7 & 8. ADDED S.A. DUCTS TO INTREX SOLID RETURN LEG. ADDED P.A. & S.A. AHT INLET DUCT CROSSOVERS. REVISED SIZE OF FW LOWER OFA DROPS: 14" O.D. (WAS 16" O.D.). ADDED DETAILS 1 THRU 4. REVISED DIMENSIONS AND ADDED DETAILS INFO WHERE INDICATED IN FIELD OF DRAWING.
C	08-20-99	AGS	REVISED IN RESPONSE TO FWUSA COMMENTS (ADDED GRADE INFO, NOTES & DWG No.'s INFO). REVISED S.A. & P.A. DUCTS AS SHOWN.
B	6/7/99	AP	ADDED PRI. AND SEC. AIR FANS AND DUCTS TO AIR HEATER. ADDED PRIMARY AIR FLOW MEASUREMENT DEVICES AT SEC. AND O.F. AIR DUCTS. REVISED O.F. AIR DUCTS AT BOILER FRONT AND REAR WALLS. DRAWING ISSUED FOR STAFF AND PERFORMANCE REVIEW.
A	5/10/99	AP	ISSUED FOR PRI.AIR AND SEC.AIR DUCT LOAD CALCULATIONS ONLY.

FOSTER WHEELER ENERGY CORPORATION
STEAM GENERATOR
ARRANGEMENT OF AUXILIARY EQUIPMENT
SECONDARY & PRIMARY AIR DUCTS
R.S. ELEVATION, SECTION A-A AND DETAILS 1 THRU 4

JEA JACKSONVILLE, FLORIDA

NORTHSIDE UNITS 1 & 2 REPOWERING PROJECT

Equipment No.: N01-BN, N02-BN

B&V Drawing No.: 62.3401.05-C0046

DRAWING NUMBER	SCALE: 3/8" = 1'-0"	REVISION
43-7587-5-300		M

DRAWN BY	AP	4/8/99	200758700 UNIT 2 DOE
CHECKED BY			200761000 UNIT 1 JEA
APPROVED BY			

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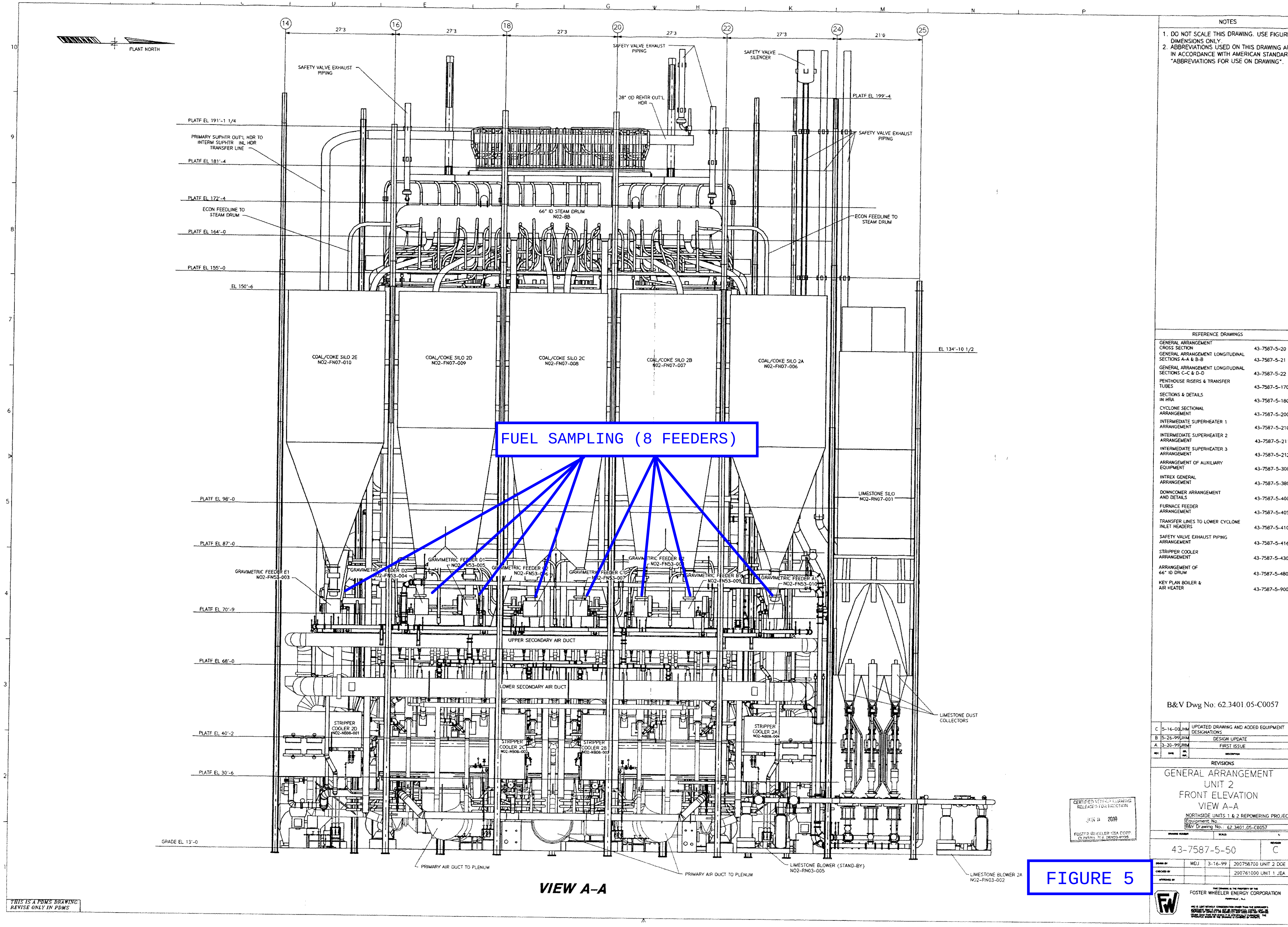

FIGURE 5

P062713.62.3401.05-C0057 St:NE 08/04/00 MM-00739

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